

# **Aggregated Dispatch of Distributed Generation Units**

## **Final Report**

*Electrotek Concepts Inc.  
Arlington, Virginia*

*New York State Energy Research and  
Development Authority  
Albany, New York*



**NREL**

**National Renewable Energy Laboratory**  
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NREL Technical Monitor: Holly Thomas

Prepared under Subcontract No. AAD-1-30605-08



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## List of Acronyms

ADC	Aggregation and Dispatch Center
APMD	average peak monthly demand
CBL	customer baseline load
DAM	Day-Ahead Market
DG	distributed generation
EDRP	Emergency Demand Response Program
EFORd	equivalent demand forced outage rate
EMS	engine management strategy
ICAP	installed capacity
LIPA	Long Island Power Authority
LSE	load-serving entity
NYCA	New York Control Area
NYDEC	New York Department of Environmental Conservation
NYISO	New York Independent System Operator
O&M	operations and maintenance
PTID	point identification number
RT	real-time
SCR	special case resource
SIC	standard industrial classification
SR	system resource
UCAP	unforced capacity

## Executive Summary

In a project funded by the New York State Energy Research and Development Authority with support from the National Renewable Energy Laboratory of the U.S. Department of Energy, Electrotek Concepts was contracted to demonstrate the technical and economic feasibility of aggregated distributed generation (DG) resources in New York State. In this effort, Electrotek proved the viability of DG aggregation in several New York Independent System Operator (NYISO) and utility programs. To achieve this objective, Electrotek designed, developed, and tested a DG aggregation system.

The objectives of this project were to develop and demonstrate the equipment and software necessary to aggregate, monitor, and dispatch multiple DG units. In this case, the DG units are local generators that are not interconnected with the bulk power system. They provide curtailment to the NYISO markets and utility curtailment programs. Under this scheme, Electrotek serves as a DG system aggregator and as the agent for NYISO transactions.

The aggregation system collects operating data from field operations, the NYISO, and utilities. In addition, the aggregation system is used to provide energy and capacity in NYISO electric markets. In other words, the DG aggregation system creates a virtual generator that can be monitored and controlled over the Internet.

This 3-year initiative began with a demonstration of the technical and economic feasibility of a limited number of DG sites participating in NYISO emergency programs. From there, it expanded to include more DG sites and more diversified market participation. Finally, Electrotek demonstrated alternative approaches with DG resources, such as the development and testing of an engine management strategy, designed to provide customers with a way to reduce energy costs through participation in NYISO capacity and energy markets.

As part of the system demonstration, Electrotek developed a portfolio of tools used in the management of activities associated with an aggregated DG system. These include tools that assist in the bidding process such as a load-forecasting model, a generator cost model, and a dispatch optimization model. With these tools, Electrotek has formulated an engine management strategy that ensures cost-effective bidding and dispatch of curtailment resources.

Today, the DG aggregation system has more than 50 sites with a total capacity of more than 40 MW participating in six programs. These program are the:

- NYISO Installed Capacity (ICAP) Market
- NYISO Emergency Demand Response Program
- NYISO Day-Ahead Market
- Long Island Power Authority (LIPA) Peak Reduction Program
- New York Power Authority Peak Reduction Program
- Con Edison Distribution Load Reduction Program.

The entire project consisted of a base-year contract and two option-year contracts. The project spanned 3 years. The base-year contract targeted developing the procedures that would enable DG technologies and included a small-scale demonstration project to prove the concept. Option Year 1 continued the progression of DG development with a field test of an aggregation of DG units and a more focused market assessment. Option Year 2 focused on a fully developed, 30-MW DG aggregation system.

In the base year, Electrotek was tasked with investigating and demonstrating the technical and economic viability of recruiting customers with back-up generators to participate in NYISO power markets. This was the starting point of a comprehensive evaluation of opportunities for DG in New York. This initiative was prescient given growing capacity problems, particularly in the New York City and Long Island areas. Under this effort, Electrotek recruited more than 5 MW of curtailment capacity and designed a control system to manage these disparate resources. This initiative demonstrated that there were opportunities for DG, particularly when they were enrolled in the NYISO ICAP Market. By participating in the ICAP Market, customers were able to collect capacity payments and energy payments.

Option Year 1 activities consisted of three tasks.

- Test the concept of aggregating DG resources in a pilot project on Long Island.
- Evaluate the availability of DG capacity in New York State and recruit 30 MW of DG units for commercial operation.
- Design the DG aggregation system structure and develop its elements.

The demonstration project was the development of the DG resources recruited in the base year. This involved developing a control system to aggregate, monitor, and control the four sites recruited; addressing the technical and administrative issues associated with enrolling these resources in the NYISO markets; and operating these resources to obtain operational data and experience.

In another Option Year 1 activity, Electrotek developed a system design for a full-scale, 30-MW DG aggregation system. This design enabled participants with a range of DG technologies to participate in several NYISO and utility programs. It also allowed some DG resources to participate in NYISO energy markets.

Finally, in Option Year 2, Electrotek developed and demonstrated the 30-MW DG aggregation system. This system has more than 50 participants and nearly 35 MW of capacity. The activities of Option Year 2 have clearly demonstrated the technical and commercial viability of DG aggregation.

This final report is a summary of the work conducted during the three phases of the project. This was a technically challenging undertaking fraught with commercial risk. With the New York State Energy Research and Development Authority's support, Electrotek has been at the forefront of the development of the systems, processes, and technologies that now enable backup generators to participate in commercial power markets. This report details how this was accomplished.

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# 1 Introduction

## 1.1 Background

Interest in the use of distributed generation and storage has increased substantially over the past 5 years because of its potential to provide increased reliability at a lower cost to customers—particularly those with on-site generation. The advent of competition in the electric power industry and the advent of customer choice have, in part, been the stimulus for this increased interest. Also contributing to this trend has been the development of small, modular generation technologies such as photovoltaic power, microturbines, and fuel cells. In addition, the environmental benefits of distributed power exploiting renewable resources, combined heat and power, and hybrid systems are substantial.

Distributed resources will account for up to 30% of new generation by 2010, according to the U.S. Department of Energy. The Department of Energy goal and vision for the 21st century is full-value distributed power captured in an electricity market in which customers can sell power, employ load management, and provide operations support services (ancillary services) as easily as the utility in an automated and adaptive electric power system. As the cornerstone of competition in electric power markets, distributed power will also serve as a key ingredient in the reliability, power quality, security, and environmental friendliness of the electric power system.

Although the application of distributed generation and storage can bring many benefits, the technologies and operational concepts to properly integrate them into the power system must be developed to realize these benefits and avoid negative effects on system reliability and safety. The current power distribution system was not designed to accommodate active generation and storage at the distribution level or, particularly, to allow distributed generation (DG) customers to supply energy to other distribution customers.

The technical issues that must be addressed to allow this type of operation are significant. For example, the control architectures for safe and reliable distributed power operation, and particularly for the exploitation of distributed power to provide grid support, will require system protection redesign. This will require large amounts of information fed to advanced, possibly neural networks and intelligent local controllers that act quickly to reconfigure and operate local distribution areas for both local and transmission-level benefits. New system architectures and the enabling hardware and software will need to be developed.

Electricity regulation, zoning and permitting processes, and business practices developed under the framework of an industry based on central station generation and ownership of generation facilities by a regulated monopoly can be barriers to the orderly development of market opportunities for distributed power in a restructured electric power industry. These barriers need to be addressed through the active and mutual participation of all parties (industry, government, etc.) to develop solutions and provide leadership and educational approaches.

The federal government has an interest and role in the systems aspect of distributed power because of its effects on competition in the electric industry, the reliability and security of the electric power supply, and the environment. In addition, the federal government has invested heavily in research and development of distributed generation and storage technologies such as fuel cells, photovoltaics, wind turbines, microturbines, combined heat and power systems, and batteries.

Working as a lower-tier subcontractor to the New York State Energy Research and Development Authority, Electrotek Concepts Inc. aggregated distributed generators in the New York metropolitan area (New York City, Long Island, and Westchester County), procured and installed the equipment needed to interconnect each participating generator and the system aggregator control room, and analyzed the results, including the economic and environmental benefits.

A special focus was on New York City and Long Island as classic examples of constrained electric power systems. Long Island, which consists of Nassau and Suffolk counties, has a population of about 3 million people and a thriving economy that have led to an increase in the demand for electricity in recent years. The peak demand in the summer of 2004 is expected to be about 5,165 MW. Consolidated Edison's peak load for 2004 is forecasted to be 12,876 MW [1].

Figure 1 is a representation of the New York Control Area (NYCA). The only transmission connections of the Long Island Power Authority (LIPA, Zone K) are with Con Edison—the distribution company for New York City and Westchester County (zones J and I, respectively)—and NEPEX (Zone N), the NEW England regional transmission operator. The transmission connections with Con Edison help maintain stability but are not significant as a source of imported electrical capacity because the Con Edison System is almost as constrained as LIPA's.

To quantify the extent of the constraints, the New York Independent System Operator (NYISO) administers a market for installed capacity. It is known as the ICAP Market. The load-serving entities (LSEs) in the Con Edison New York City zones (I and J) are required to have access to sufficient capacity to meet their predicted monthly peak demand. The local ICAP requirement for Zone I and Zone J (New York City and Westchester County)—that is, the capacity located within these zones—is 80% of the predicted peak demand. This requirement is directly related to the limited transmission capacity. The LSEs on Long Island (Zone K) have a local ICAP requirement of 98% of the predicted peak demand.

Although there are many applications to site new generating resources in both service territories, they are severe non-attainment areas for ozone and generally difficult areas in which to site new generation. In the summer of 2001, the NYISO identified deficiencies of about 400 MW in Con Edison territory and 130 MW in LIPA service territory. The NYISO conducted ICAP deficiency auctions (because every LSE did not have sufficient capacity to meet peak demand) in which the NYISO bid higher than market prices to close the gap. The proposed new electric generation units for New York State require the interconnections in Figure 2.

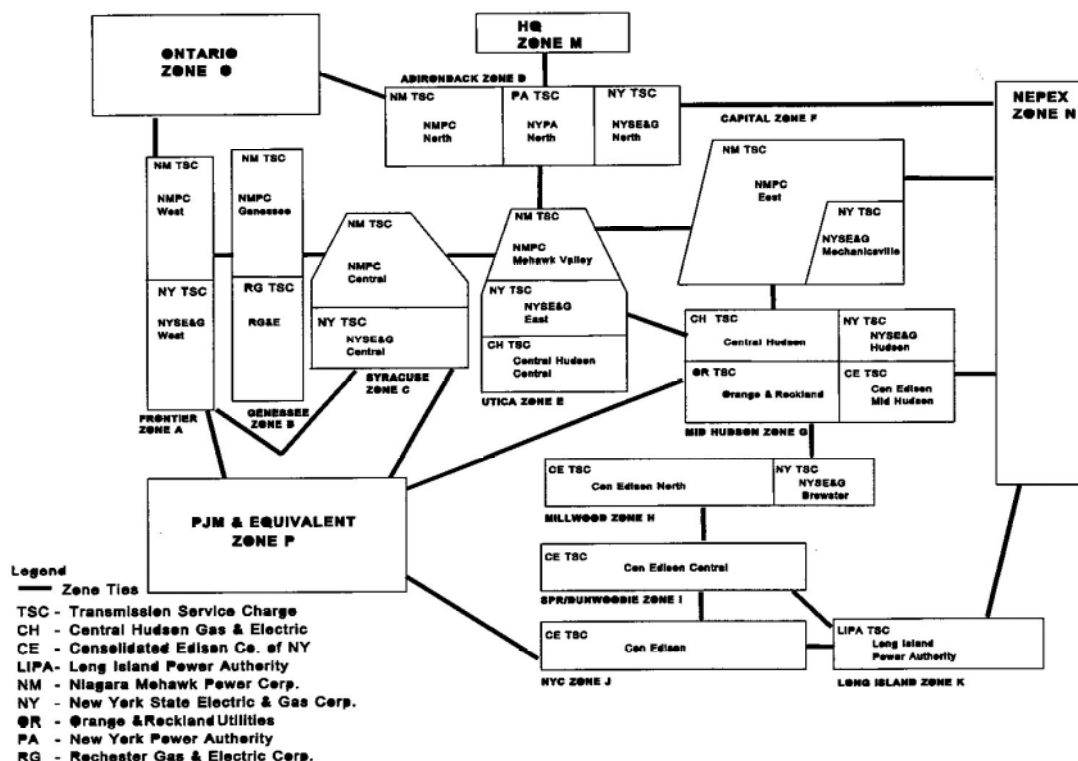
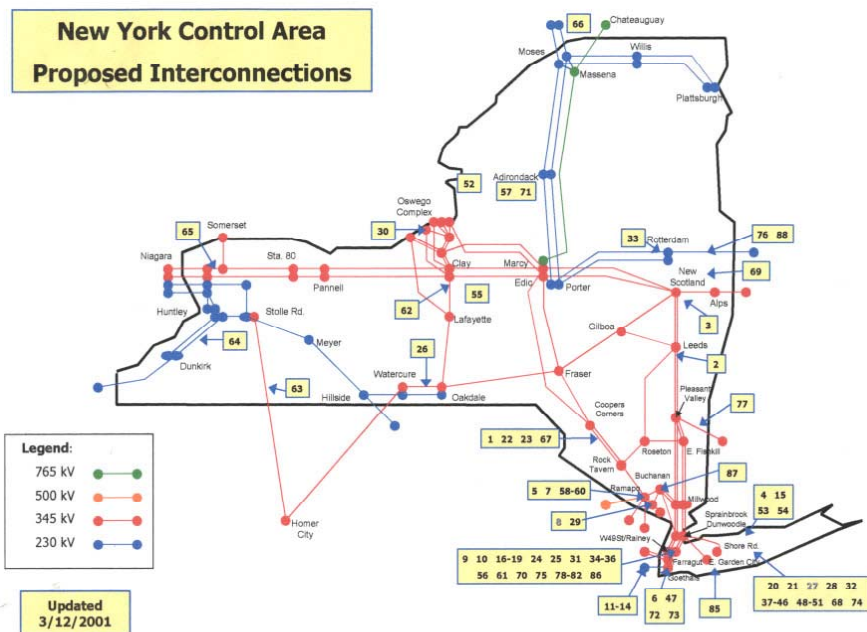


Figure 1. New York Control Area transmission districts

Figure 2 shows the new interconnections needed to maintain system reliability as demand for electricity increases. The most important new interconnection is the DC cable project across Long Island Sound between Connecticut and Shoreham. The 330-MW project, estimated to cost more than \$200 million, has been rejected by the State of Connecticut because it would create pollution in Connecticut to satisfy the demand for electricity on Long Island. In addition, issues related to the installation of the cable and its potential safety and environmental effects cloud its availability.

To the extent that DG projects are able to help meet peak demand, such projects can help maintain system reliability while enabling the DC cable project to be delayed. Also, the rejected DC cable project can serve as a measure of the transmission-saving benefits of DG projects on Long Island.



**Figure 2. New York Control Area proposed interconnections**

## 1.2 Objective

The objective of this project was to demonstrate the aggregation of backup generators by adding controls to make them immediately dispatchable from a single point to provide spinning reserve, interruptible load, and peak power to the utility grid and an independent system operator.

Contract activities included:

- Recruiting facilities with backup generators for 30 MW of capacity
- Aggregating distributed backup generators by adding controls to make them immediately dispatchable from a single control point as required for reduction in peak demand on the utility grid
- Procuring and installing the equipment needed to interconnect each participant's generator with the system aggregator control room
- Quantifying the costs and value of services that could be supplied by the system aggregator and the applicable technical and institutional constraints.

### 1.3 Approaches

To accomplish the objectives, the following tasks were performed over the 3 years of the project:

- DG resources available in New York State for aggregation were evaluated. The goal of this assessment was to:
  - Find out total installed capacity and total generation potential
  - Determine typical types and sizes of single gensets
  - Find a geographical distribution of the generators
  - Determine major implications associated with the use of these resources for peak-shaving or load-modification activities.
- A New York State energy market assessment was conducted to find:
  - Potential markets for DG participation
  - Conditions and requirements for generators to be sold to particular markets
  - Potential costs benefits for clients and LSEs.
- A DG aggregation system was designed and built using the following steps:
  - Requirements for the system architecture and its components were developed.
  - The control and monitoring structure for the aggregation and dispatch of distributed generators was designed, and control and monitoring equipment were installed on generators.
  - Software and supporting computer tools—necessary for the collection, storage, and management of data as well as the control and dispatch of the generators—were developed and implemented
  - Two control centers were designed and built: the Data Collection and Management Center and the Control and Dispatch Center.
- The pilot DG aggregation system was tested at 10 facilities on Long Island. These facilities had 12 generators with a total installed capacity of about 5 MW.
- The pilot system was expanded into a commercial DG aggregation system with more than 50 generators.

The project demonstrated a system that enables DG units to participate in regional competitive markets in a manner similar to large, central station power plants. The concept also demonstrated an approach that greatly simplifies technical interconnection issues and transactions with local distribution companies. Some extensions are now under way to expand possible integration arrangements.

In New York State, for example, such an approach could be used to provide ancillary services. The primary ancillary services markets in the NYISO that could be served by DG are the:

- 10-Minute Spinning Reserves
- 10-Minute Non-Synchronized Reserves
- 30-Minute Operating Reserves.

This report provides descriptions of the activities identified above. DG aggregation is now under fast development. Over the 3-year period of this project, some activities were repeated because of changing rules and conditions in energy markets or to refine systems and procedures to improve their technical or market performance.

## **2 Market Assessment and Preliminary Costs and Benefits Analysis**

Before a DG aggregation system was designed and built, three questions had to be answered:

1. What energy markets for DG are available in New York State?
2. What DG is available to participate in New York State energy markets?
3. What costs and benefits can be expected for different arrangements of aggregated DG when participating in energy markets?

This section describes analyses conducted by Electrotek before and during the development and construction of the commercial, 30-MW aggregated DG system.

### **2.1 Energy Markets in New York State**

#### **2.1.1 New York Independent System Operator Markets**

DG can participate in four markets in the NYISO: the ICAP Market, the energy market, the Ancillary Services Market, and the Emergency Demand Response Program (EDRP). These markets are administered by the NYISO in accordance with rules detailed in the Open Access Transmission Tariff and numerous NYISO manuals.

In this section, each of the major markets—ICAP, energy, and Ancillary Services—will be detailed. Each of these markets will also be broken down into component markets.

##### **2.1.1.1 Installed Capacity Market**

The NYISO ICAP Market is the market for capacity administered by the NYISO. This market has two 6-month planning cycles, or capability periods. The winter capability period runs from November through April; the summer capability period runs from May through October. Each capability period has a series of six monthly capacity auctions, a 6-month strip auction, and, if necessary, monthly spot auctions (formerly known as deficiency auctions).

The planning and procurement process for the NYISO ICAP Market begins with the New York State Reliability Council. The New York State Reliability Council is a not-for-profit entity responsible for developing, maintaining, and updating the reliability rules for the NYISO and all parties engaged in electric transmission, ancillary services, and energy and power transactions on the New York State power system.

The New York State Reliability Council determines the NYCA reserve margin on an annual basis. Next, the NYISO determines the ICAP requirement for the NYCA in accordance with the reliability rules and standards of the New York State Reliability Council and the Northeast Power Coordinating Council. The NYISO then converts the NYCA installed capacity requirement into an NYCA unforced capacity (UCAP) requirement. A generator's UCAP value is obtained by multiplying the ICAP value by the quantity 1 minus the average forced outage rate for all resources in the NYCA.

Upon estimation of the NYCA UCAP requirement, the NYISO determines the locational ICAP requirements for the 11 NYISO zones. Locational ICAP is generating capacity physically located within a specific zone, i.e., local (zonal) generating capacity. This locational ICAP requirement is based on the load and local generating capacity within each zone as well as the available transmission capacity to each zone. Thus, transmission-constrained areas will tend to have higher locational ICAP requirements as a percentage of total zonal load. This is the case in two NYISO zones: Zone J (New York City) and Zone K (Long Island).

ICAP resources face a number of requirements. First, ICAP resources must be in full compliance with New York Department of Environmental Conservation registration and emissions regulations. This means these resources must be registered with the department with a state facilities permit, a Title V registration, or an air facilities registration. Each of these classifications places a cap on total emissions for a facility. All ICAP resources sold in the NYCA either bilaterally or in NYISO markets must be certified on a monthly basis with the NYISO. This certification process registers all transactions with the NYISO and provides a basis for determining whether these ICAP resources satisfied their transaction obligations. In addition, for most ICAP resources, maintenance scheduling and outage reports must be filed with the NYISO. This ensures all certified capacity not in service because of maintenance or outage is reported as unavailable to the NYISO. Finally, there are operating data reporting requirements for all resources.

There are six types of ICAP resources in the NYISO. These are:

- Generators and system resources (SRs)
- Energy-limited resources
- Interruptible load resources
- Municipally owned generation
- Special case resources (SCRs)
- Intermittent power resources.

Each of these is described below.

#### **2.1.1.1.1 Generators and System Resources**

Generators are interconnected units that can inject power into the grid. A generator must have at least 1 MW of capacity to be certified in the NYISO ICAP Market. All generators participating in NYISO markets must undergo a demonstrated maximum net capability test to verify their certified capacity value. Demonstrated maximum net capability tests are typically used to determine a unit's sustained maximum net output averaged over a period of 4 hours. Generators must also provide the NYISO with planned maintenance schedules, which may be voluntarily rescheduled at the NYISO's request.

An SR is a portfolio of UCAP provided by multiple sites or units in a single NYISO zone and owned or controlled by a single entity. An SR is offered in whole or part to the NYISO and, like generators, must have a minimum capacity of 1 MW. An SR must also undergo a demonstrated maximum net capability test and must also be able to operate in Day-Ahead or Real-Time (RT) energy markets. An example of an SR is a set of small distributed generators located within a single NYISO zone and aggregated to satisfy the 1-MW minimum capacity threshold.

#### **2.1.1.1.2 Energy-Limited Resources**

Energy-limited resources are capacity resources that—because of design considerations, environmental restrictions, cyclical requirements, or other non-economic reasons—are unable to operate continuously on a daily basis but are able to operate for at least 4 consecutive hours each day. Typically, such resources include storage units (e.g., pumped storage or compressed air energy storage) and units whose operation is restricted by emission limits.

#### **2.1.1.1.3 Interruptible Load Resources**

An interruptible load resource is a load that is obligated, under a contract, to be interrupted when required by the independent system operator. Interruptible loads must prove through demonstrated maximum net capability tests that they are capable of the contract reduction in consumption in response to an NYISO request. Like generators and SRs, interruptible load resources that sell capacity in the ICAP Market are obligated to offer their load in the Day-Ahead or RT energy markets.

#### **2.1.1.1.4 Municipally Owned Generation**

A municipal utility that owns generation in excess of its installed capacity requirement may qualify that excess capacity as UCAP in the ICAP Market. To do so, the municipal utility must provide the NYISO with the physical operating parameters of the generation and operate the excess generation capacity in accordance with NYISO ICAP market rules. However, for generation in service or under construction as of Dec. 31, 1999, exemptions for bidding, scheduling, and notification requirements may be sought.

#### **2.1.1.1.5 Special Case Resources**

SCRs are loads capable of being interrupted upon demand and distributed generators 100 kW or more that are not visible to NYISO's Market Information System. The UCAP of an SCR corresponds to its pledged load reduction adjusted by historical performance factors and increased by the transmission district loss factor to account for transmission losses that would be incurred in serving the SCR site load. SCRs are required to demonstrate their capability once in each capability period with a 1-hour test.

Because of their smaller size and the fact that few of the DG units in New York are interconnected, these units would only be eligible for the ICAP Market as SCR. This allows them to receive a capacity payment based on the load they are able to curtail and obligates them to curtail when called.

The UCAP of SCRs may be sold in the ICAP Market or in bilateral transactions. If sold, SCRs must provide their energy or curtailment for a minimum 4-hour block when called. SCRs are only dispatched when system reserve margins are deficient. These resources are not required to bid in energy and ancillary service markets.

#### **2.1.1.1.6 Intermittent Power Resources**

Intermittent power resources are capacity resources that rely on the wind or sun for generation. These resources are dependent on sources that cannot be readily scheduled for production, and their capacity value may vary based on the availability of the driver (i.e., wind or sun). Such resources are considered irregular capacity, but they may qualify as ICAP suppliers without having to comply with the daily bidding and scheduling requirements of other suppliers. To qualify as ICAP suppliers, intermittent power resources must comply with standard notification requirements. In addition, to calculate UCAP for an intermittent power resource, the historical capacity factor will be adjusted to remove the effects of outages.

#### **2.1.1.2 Energy Market**

The NYISO has two energy markets: the Day-Ahead Market (DAM) and the RT Market. Market participants—excluding SCRs, qualified intermittent power resources, and qualified municipally owned generators—must offer their UCAP in either of the energy markets or in the Ancillary Services Market to satisfy the requirements of the ICAP Market, detailed above. The Day-Ahead and RT energy markets are detailed below.

The NYISO DAM relies on the Security Constrained Unit Commitment program to schedule resources and determine the locational-based marginal price, which is the hourly zonal electricity price. The Security Constrained Unit Commitment program evaluates load forecasts and the price and availability of resource bids to prepare a generation schedule for the next day. The Security Constrained Unit Commitment program uses an optimization model that minimizes the total production cost of energy while satisfying reliability and generator performance constraints (e.g., ramp rates and minimum run time).

The RT Market is used to balance the scheduled DAM dispatch, which is based on forecasted loads, with the actual loads on the system. In New York State, the RT Market accounts for roughly 5% of the total energy of the system. It serves as a balancing market.

#### **2.1.1.3 Ancillary Services Market**

Ancillary services are those services necessary to support the transmission of energy from generators to loads. In the NYISO, there are six ancillary services. Of these, three are market-based, and three are provided by the NYISO and paid for through embedded costs. The NYISO coordinates the provision of all ancillary services and directly arranges for the supply of all ancillary services that are not self-supplied. Some ancillary services must be provided by the NYISO, and others may be self-supplied. Table 1 summarizes the ancillary services in the NYISO.

**Table 1. Available Ancillary Service**

<b>Ancillary Service</b>	<b>Location-Based</b>	<b>Provider</b>	<b>Pricing</b>
Scheduling, system control, and dispatch	No	NYISO	Embedded
Voltage support	Yes	NYISO	Embedded
Regulation and frequency response	Yes	NYISO or self-supply	Market-based
Energy imbalance	No	NYISO	Market-based
Operating reserves	Yes	NYISO or self-supply	Market-based
Black start	Yes	NYISO	Embedded

Because the DG resources considered here are not interconnected with the grid, the only ancillary service they are able to provide is operating reserves. Operating reserve service provides backup generation in the event major generating resources trip off-line because a power system contingency or equipment failure. Most of the reserves must be available from units within the NYCA and within specific regions, as required by the New York State Reliability Council.

Three types of reserves are sold in the NYISO Ancillary Services Market:

- **10-Minute Spinning Reserves**  
Operating reserves provided by generators and interruptible/dispatchable load resources within the NYCA that are already synchronized to the New York State power system and can respond to instructions to change output level within 10 min.
- **10-Minute Non-Synchronized Reserves**  
Operating reserves provided by generators that can be started, synchronized, and loaded within 10 min. These reserves are carried on quick-start units such as gas turbines.
- **30-Minute Spinning Reserves**  
30-minute spinning reserve provided by generators and interruptible/dispatchable load resources within the NYCA that are already synchronized to the New York State power system.

Curtailable loads can participate in any of the reserve markets. They must be registered and certified in the ICAP Market before participating in the Ancillary Services Market.

#### ***2.1.1.4 New York Independent System Operator Emergency Demand Response Program***

The EDRP was established by the NYISO in May 2001. The EDRP was originally a 2-year program that provided necessary load reduction during emergency conditions. The program is voluntary and pays participants to reduce load through curtailment or on-site generation. The facilities in this project are all emergency generators that have participated in the EDRP.

In April 2001, the New York Department of Environmental Conservation (NYDEC) amended 6 NYCRR Part 200, General Provisions, Part 201, Permits and Registration, Subpart 225-1 to allow the participation of emergency generators in the EDRP. This participation is limited to 150 MW of capacity per event. The 150-MW capacity limit was expected to be revised downward for the summer of 2002.

Under the EDRP, participants are given no less than 2 hours' notice for up to 4 hours of load reduction. There are two methods of determining the amount of load reduction provided. For facilities with on-site generation, generator output can be metered. For others, a historical baseline is developed based on the average hourly load of the five highest recent days over a 10-day period. Reduction below this baseline is the defined curtailment. Originally, the NYISO paid the participant the greater of \$500/MWh or the real-time locational-based marginal price. Currently, resources bid their EDRP curtailment energy, with dispatch of EDRP resources determined by the locational need and the price.

#### ***2.1.2 Long Island Power Authority Peak Reduction Program***

The LIPA has a Peak Reduction Program that provides customers with financial incentives to reduce loads. The participation threshold is 50 kW of load reduction. On critical days during the summer (June 1–Sept. 30), LIPA calls on these customers to reduce load between the hours of 2 p.m. and 6 p.m. and credits their bills by \$6.43/kW for the curtailment. The notification period is at least 4 hours before curtailment.

#### ***2.1.3 Selection of Markets***

Based on the characteristics of the NYISO markets, a number of conclusions should be restated. First, diesel generation can only participate in the NYISO EDRP or in the ICAP Market as an SCR. The emission levels associated with diesels preclude their participation in energy or ancillary services markets. Furthermore, the new DG rules being promulgated by NYDEC are likely to explicitly exclude their operation in energy and ancillary services markets. Additionally, turbines in this analysis are considered only in energy and ancillary services markets. Although they can and do participate in EDRP and ICAP markets, as SCRs, they are not considered in those markets here because the financial incentives for participation in energy and ancillary services markets are much greater.

### **2.2 Distributed Generation Resources in New York State**

The Electric Power Research Institute has estimated that the installed capacity of DG consists primarily of cogeneration units and units installed to provide backup electric service. Because of the immaturity of the markets, most cogeneration units are not part of an aggregated group of generators routinely dispatched to provide services (energy or ancillary) to support the electric power system. However, there are 5,000 MW of installed cogeneration capacity in the United States.

DG resources targeted in this project are primarily emergency generators installed in office buildings, hospitals, and industrial enterprises. These generators are typically diesel engines, gas turbines, and natural gas-fired reciprocating engines. The generators are designed to operate when disconnected from commercial service so they can be used for curtailment but cannot work in parallel with the grid unless special interconnection equipment is installed.

The evaluation of available capacity of DG in New York State revealed several problems. First, a list of generators could not be obtained from a single source, such as the NYDEC, because of disclosure restrictions. Second, although the sizes and types of generators could be obtained from some sources, it was not clear what capacity was available for curtailment. Some users, such as information technology groups, install emergency generators with the capacity to cover the entire building load and even have redundant reserve. Other generators have the capacity to cover only essential loads. The latter situation is typical for large hospitals, where emergency generators usually provide energy for operating rooms, emergency rooms, and intensive care units. Therefore, it is necessary to know not only a facility's installed capacity but also what load is available for curtailment.

For these reasons, the evaluation of DG resources in New York was conducted state in two steps:

1. Carry out a detailed estimate for the LIPA service territory.
2. Extrapolate these results to the entire state based on population and economic circumstances.

### ***2.2.1 Generation Profile of Distributed Generation Resources on Long Island***

In the first stage of the project, Electrotek developed a preliminary estimate of the amount and characteristics of installed backup capacity on Long Island. This resulted in useful information about the typical demand profiles of prospective participants.

#### ***2.2.1.1 Preliminary Generation Profile of Distributed Generation in the Long Island Power Authority Service Territory***

During the preliminary survey on Long Island, Electrotek observed several cogenerators. These resources appeared to be well-suited for providing valuable peaking capacity and operating reserves—services that could command high prices if aggregated and made dispatchable.

The reason is that it is not unusual to find cogeneration units sized to supply thermal load, which is deemed to be a critical load. The installations usually operate in parallel with the utility and import power from the utility. In addition, there are usually several generating units to enable the full thermal load to be supplied even if one generator is out of service. The extra generator can be used to supply peaking capacity and operating reserve capacity to the utility.

LIPA has a peak demand of about 5,000 MW. (This represents about 2% of the peak demand of the United States.) Using the Electric Power Research Institute's estimate of 5,000 MW of cogeneration capacity, one can infer about 100 MW of cogeneration, a capacity that is quite credible given the number of hospitals, hotels, and processing facilities on Long Island. A key question, then, for this project is how many cogeneration facilities have been installed with reserve/backup capacity that may be available for aggregated dispatch.

The second type of DG, backup generators, has been estimated to have an installed capacity in the United States equal to 10% of the peak demand of 900 GW, or about 90,000 MW nationally and 540 MW in the LIPA service territory. This estimate is easily accounted for, even in the very preliminary survey.

Electrotek then collected data from organizations that agreed to provide information about their electric demand, their backup generators, and their operating practices. These organizations are listed in Table 2.

**Table 2. Installed Backup Generator Capacity and Demand (MW)**

<b>Organization</b>	<b>Backup Generator Capacity</b>	<b>Demand</b>
Verizon	30	16
Brookhaven National Laboratory	8	8
Entenmann's	2	2
LIPA	200	100
Hospitals	25	50
Hotels/Motels	80	50
Universities	60	30
JP Morgan Chase/Data Centers	80	50
Reuters	4	2
<b>TOTAL</b>	<b>490</b>	<b>315</b>

The most detailed information is for Verizon, Entenmann's, Reuters, and Brookhaven National Laboratory. The backup generator capacity identified to date is actually very close to the 10% estimate used.

#### ***2.2.1.2 Typical Demand Profiles of Distributed Generation Owners***

Typically, backup generators supply the entire load of the facilities in which they are located. That means the capacity of these generators must be greater than or equal to the maximum peak demand. Otherwise, the owners must isolate circuits. Backup generator capacity is usually about twice the peak demand of the circuit it normally supplies. Many owners have a relatively high capacity factor.

Table 2 shows that the output of the typical backup generator is limited by the demand of the facility in which it is located rather than by the capacity of the machine. Therefore, the potential effect of backup generators may be extended by putting in the switchgear to enable them to operate in parallel with the distribution circuit. Interconnection is a costly step, but it is clear that on Long Island there are potential benefits.

#### **2.2.1.2.1 Verizon**

Evidence of the problems on eastern Long Island is provided by the experiences of Verizon, which owns about 40 buildings there with 21 MW of demand and almost twice that in backup capacity. These buildings have backup generators, which operate frequently because of low voltage conditions on the LIPA system. There are both gas turbines and diesel engines.

Most of the facilities have very high load factors. The largest facilities have capacity factors of about 65% and 75%. This is indicative of an around-the-clock data center with administrative functions that cause a small increase in demand during traditional working hours and a load fluctuation because of air conditioning in the summer.

#### **2.2.1.2.2 Entenmann's**

Entenmann's is a major supplier of baked products in the New York area. Its major production facility is in Jericho, New York. The facility has four 1,300-kW engines. Three are reciprocating engines operated as base load cogenerating units; the fourth, a diesel engine, serves as a backup generator. During the winter, Entenmann's is self-sufficient. In the summer, it imports about 1,100 kW from LIPA and could use its backup generator to sell capacity and energy. In addition, the use of cogeneration could be examined for the potential to sell NOX allowances.

#### **2.2.1.2.3 Computer Associates**

Computer Associates is located in Hauppauge, New York. It operates a data center with a fairly high load factor. It has an installed backup generator capacity of 14 MW and a 9-MW load.

#### **2.2.1.2.4 Reuters**

Reuters is located in Bohemia, New York. It has a backup generator capacity of about 4 MW and a curtailable load of 2 MW.

### **2.2.2 Evaluation of Distributed Generation Resources for the Rest of New York State**

Results obtained during the evaluation of distributed generators on Long Island provided Electrotek with a great deal of knowledge about the typical installations of emergency generators and their sizing. It also provided information about typical load profiles for different kinds of customers. Unfortunately, because of a multitude of factors, these results did not successfully extrapolate for all of New York State. Therefore, Power Systems Research Corp. (PowerSys) of Eagan, Minnesota, was engaged by Electrotek to compile a list of backup generators in New York State.

#### **2.2.2.1 Generator Database**

The analysis conducted for this report is based on a database inventory of emergency backup generators provided by PowerSys. For each generator, the database includes the county, capacity, type of generator, fuel type, vintage, and type of business the owner of the generator is engaged in. A detailed description of the database was provided in a previous report [2].

A review of the database found some omissions. These exclusions were generators known to Electrotek that were not in the database file provided by PowerSys. Although these omissions cannot be dismissed, Electrotek did not believe they warranted a diminution of the value of the data. Although the database cannot be considered all-inclusive, it does represent the most comprehensive accounting of DG resources in New York State.

The original database listed DG resources of all sizes, including units as small as 10 kW. For this study, units less than 100 kW of capacity were excluded. This is because the minimum size of units allowed to participate in NYISO programs is 100 kW.

A compilation of the data revealed some interesting information. Table 3 shows the total generating capacity of DG units with capacities of 100 kW or more by generator type and by county. There are more than 3,582 MW of capacity across the state. Most of this capacity, 2,896 MW or 80%, is from reciprocating engines, and the balance is from turbines.

Table 4 shows the number of generators by type and by county. There were 10,542 generators of at least 100 kW of capacity in all of New York State in the database. Of these, most were reciprocating engines. Turbines accounted for only 460 of the total. Across the state, the average capacity of a reciprocating engine was 285 kW, and the average turbine was more than 1.5 MW.

Another interesting point is that there were nine counties with a total DG capacity of more than 100 MW. These counties were: Dutchess, Erie, Kings, Monroe, Nassau, New York, Queens, Suffolk, and Westchester. Of these, Erie County had the most capacity (124 MW). Most of these counties are in the New York City and Long Island areas, which are the areas in most need of capacity.

**Table 3. New York State Distributed Generation Resources: Installed Capacity (MW)**

<b>New York State DG Resources – MW</b>											
<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>	<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>	<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>
Albany	50.2	16.3	66.5	Herkimer	29.7	8.7	38.4	Richmond	42.9	12.1	55.0
Allegany	29.5	4.9	34.3	Jefferson	31.6	9.6	41.2	Rockland	55.2	9.2	64.3
Bronx	76.9	18.1	95.0	Kings	83.5	21.2	104.7	Saratoga	39.4	6.8	46.2
Broome	52.3	11.1	63.4	Lewis	35.3	8.6	43.9	Schenectady	59.6	15.5	75.0
Cattaraugus	70.9	18.4	89.3	Livingston	41.4	8.9	50.3	Schoharie	30.0	4.8	34.8
Cayuga	36.7	8.5	45.3	Madison	38.0	9.7	47.8	Schuyler	21.6	7.3	28.9
Chautauqua	73.4	24.9	98.3	Monroe	84.4	24.2	108.6	Seneca	19.7	8.0	27.7
Chemung	37.7	4.7	42.4	Montgomery	35.5	5.0	40.5	St. Lawrence	49.0	13.6	62.7
Chenango	34.5	7.0	41.5	Nassau	89.2	22.1	111.3	Steuben	27.9	14.7	42.6
Clinton	33.1	9.0	42.1	New York	87.9	21.3	109.2	Suffolk	89.7	28.0	117.7
Columbia	31.4	4.4	35.8	Niagara	69.2	15.2	84.4	Sullivan	56.8	13.1	69.9
Cortland	35.3	6.0	41.3	Oneida	56.8	14.5	71.2	Tioga	29.5	2.5	32.0
Delaware	35.1	7.1	42.2	Onondaga	77.6	20.4	98.0	Tompkins	31.2	10.5	41.7
Dutchess	85.2	23.1	108.3	Ontario	41.5	5.9	47.4	Ulster	37.6	12.8	50.4
Erie	90.4	33.5	124.0	Orange	62.4	13.6	76.0	Warren	35.8	6.0	41.8
Essex	34.3	8.3	42.5	Orleans	32.9	3.0	35.9	Washington	20.3	6.2	26.5
Franklin	34.6	9.4	43.9	Oswego	39.4	6.8	46.2	Wayne	24.8	5.5	30.3
Fulton	30.6	9.4	40.0	Otsego	35.3	7.5	42.7	Westchester	89.0	27.1	116.1
Genesee	31.7	7.1	38.8	Putnam	32.1	6.0	38.1	Wyoming	25.9	6.4	32.4
Greene	22.0	4.9	26.9	Queens	85.9	24.2	110.1	Yates	6.1	0.0	6.1
Hamilton	22.2	4.9	27.1	Rensselaer	40.2	5.7	45.9	<b>Total</b>	<b>2,869.8</b>	<b>712.9</b>	<b>3,582.7</b>

**Table 4. New York State Distributed Generation Resources: Number of Generators**

<b>New York State DG Resources - Generators</b>											
<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>	<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>	<b>County</b>	<b>Recip</b>	<b>Turbine</b>	<b>Total</b>
Albany	160	11	171	Herkimer	107	5	112	Richmond	151	7	158
Allegany	110	3	113	Jefferson	115	6	121	Rockland	199	7	206
Bronx	271	12	283	Kings	293	15	308	Saratoga	140	5	145
Broome	185	8	193	Lewis	121	5	126	Schenectady	204	10	214
Cattaraugus	245	14	259	Livingston	146	6	152	Schoharie	107	3	110
Cayuga	131	6	137	Madison	135	5	140	Schuyler	72	5	77
Chautauqua	253	16	269	Monroe	299	15	314	Seneca	64	6	70
Chemung	135	3	138	Montgomery	125	4	129	St. Lawrence	179	8	187
Chenango	122	5	127	Nassau	315	14	329	Steuben	96	7	103
Clinton	117	5	122	New York	309	14	323	Suffolk	316	15	331
Columbia	111	4	115	Niagara	245	9	254	Sullivan	200	10	210
Cortland	132	4	136	Oneida	201	9	210	Tioga	108	2	110
Delaware	123	5	128	Onondaga	277	14	291	Tompkins	110	7	117
Dutchess	288	14	302	Ontario	145	5	150	Ulster	128	8	136
Erie	318	16	334	Orange	220	10	230	Warren	129	4	133
Essex	122	6	128	Orleans	116	2	118	Washington	78	4	82
Franklin	120	6	126	Oswego	141	4	145	Wayne	89	4	93
Fulton	104	6	110	Otsego	119	6	125	Westchester	311	17	328
Genesee	113	5	118	Putnam	114	3	117	Wyoming	91	5	96
Greene	83	3	86	Queens	299	14	313	Yates	13	0	13
Hamilton	70	4	74	Rensselaer	142	5	147	<b>Total</b>	<b>10,082</b>	<b>460</b>	<b>10,542</b>

#### **2.2.2.2 Algorithms and Assumptions**

To estimate the generating capacity available in New York State for participation in NYISO markets, several factors must be considered. First, under current NYISO rules, reciprocating engine generators are ineligible to participate in energy or ancillary services markets. In addition, the NYDEC is currently promulgating new rules for DG resources in New York. Although final rules are pending, it is clear that the allowable emission levels for DG will be very stringent and preclude the possibility of diesel-fired generation without external pollution control. Thus, reciprocating engine generators will only be eligible to participate in the NYISO EDRP and in the ICAP Market as SCRs—and only after they have registered with NYDEC.

Turbine generators can participate in energy and ancillary services markets if they satisfy appropriate NYDEC and local permitting requirements. For NYDEC, this would likely require a state facilities permit, which would cap NOX emissions at 12.5 tons per year. Larger facilities would require a Title V permit, though the turbines included in this study—the largest of which is 2.6 MW—would not warrant such a permit. In this analysis, the turbine generators are considered only for energy and ancillary services markets because these offer the greatest financial incentives for participation.

Finally, it is necessary to consider these resources by industry-specific characteristics. Different industries have different requirements for the amount of backup generation needed. For example, facilities such as financial institutions, telecommunication centers, and data processing centers typically need redundancy of back-up generation. The criticality of their loads means a facility with a 1-MW load could have 2 MW of backup generation to provide protection against an outage of a backup generator. Other industrial sectors have less critical loads and typically do not have redundant backup generation. In fact, they may not have their entire load served by the backup generator.

To account for these sectoral anomalies, a curtailment ratio was developed for each two-digit Standard Industrial Classification (SIC). This ratio is the amount of generating capacity that would actually curtail load during dispatch. These ratios were estimated based on Electrotek's experience across a range of clients with DG resources. Although principally based on professional judgment, it represents a reasonable first-order estimate of the amount of actual curtailment that could be realized by each generator in a sector.

To estimate the technical potential for DG, total DG capacity was summed by sector and then multiplied by the curtailment ratios provided in Appendix A. It should be noted that there are two distinct classifications for capacity. The first is for reciprocating engines. These generators can participate only in the NYISO EDRP or the NYISO ICAP Market as SCRs. The second classification is for turbines, which are eligible to participate in energy and ancillary services markets.

### 2.2.2.3 Results

The evaluation of the technical potential for DG in New York is an estimate of the capacity technically capable of participating in NYISO markets. Two market categories have been evaluated: (1) EDRP and SCRs and (2) energy and ancillary services markets. Because the database provided generator data by generator type (turbines and reciprocating engines) and by SIC code, it is possible to develop the technical market potential by market category and by SIC code. That is what was done in this study.

Table 1 shows the technical market potential for curtailment in New York by SIC code and for the entire state.

**Table 5. Technical Market Potential by Sector**

<b>SIC Code</b>	<b>Description</b>	<b>EDRP/SCR Capacity (MW)</b>	<b>Energy/ Ancillary Services Capacity (MW)</b>	<b>Total (MW)</b>
01	Agricultural Production Crops	2.4	0.0	2.4
07	Agricultural Services	2.9	1.2	4.1
08	Forestry	0.1	0.0	0.1
09	Fishing, Hunting, and Trapping	0.1	0.0	0.1
13	Oil and Gas Extraction	0.7	0.0	0.7
15	Building Construction – General Contractors and Operative Builders	20.5	1.5	22.0
16	Heavy Construction Other Than Building Construction Contractors	3.5	0.0	3.5
17	Construction – Special Trade Contractors	15.1	2.9	18.0
20	Food and Kindred Products	17.3	18.7	35.9
21	Tobacco Products	0.5	0.0	0.5
22	Textile Mill Products	13.3	3.0	16.2
23	Apparel and Other Finished Products Made From Fabrics and Similar Materials	45.1	5.4	50.5
24	Lumber and Wood Products, Except Furniture	0.6	0.0	0.6
25	Furniture and Fixtures	4.2	0.0	4.2
26	Paper and Allied Products	9.6	9.5	19.2
27	Printing, Publishing, and Allied Industries	55.7	19.6	75.3
28	Chemicals and Allied Products	6.2	1.2	7.4
29	Petroleum Refining and Related Industries	0.2	0.0	0.2
30	Rubber and Miscellaneous Plastics Products	5.5	0.5	6.0

<b>SIC Code</b>	<b>Description</b>	<b>EDRP/SCR Capacity (MW)</b>	<b>Energy/ Ancillary Services Capacity (MW)</b>	<b>Total (MW)</b>
31	Leather and Leather Products	1.4	0.0	1.4
32	Stone, Clay, Glass, and Concrete Products	1.8	0.0	1.8
33	Primary Metal Industries	2.9	0.0	2.9
34	Fabricated Metal Products, Except Machinery and Transportation Equipment	17.0	8.2	25.2
35	Industrial and Commercial Machinery and Computer Equipment	4.9	1.1	6.1
36	Electronic and Other Electrical Equipment and Components, Except Computer Equipment	16.9	0.0	16.9
37	Transportation Equipment	4.4	2.2	6.6
38	Measuring, Analyzing, and Controlling Instruments; Photographic, Medical, and Optical Goods; Watches and Clocks	11.1	3.4	14.5
39	Miscellaneous Manufacturing Industries	21.6	0.8	22.4
40	Railroad Transportation	1.0	0.0	1.0
41	Local and Suburban Transit and Interurban Highway Passenger Transportation	37.3	5.6	42.9
42	Motor Freight Transportation and Warehousing	18.4	4.6	23.0
43	United States Postal Service	6.3	0.0	6.3
44	Water Transportation	0.4	2.0	2.4
45	Transportation by Air	7.7	0.0	7.7
47	Transportation Services	10.0	0.0	10.0
48	Communications	19.7	4.2	23.9
49	Electric, Gas, and Sanitary Services	3.0	1.3	4.3
50	Wholesale Trade – Durable Goods	79.0	17.5	96.4
51	Wholesale Trade – Nondurable Goods	26.4	10.9	37.3
52	Building Materials, Hardware, Garden Supply, and Mobile Home Dealers	6.0	4.9	10.9
53	General Merchandise Stores	17.0	8.2	25.2
54	Food Stores	25.6	4.0	29.6
55	Automotive Dealers and Gasoline Service Stations	16.2	1.1	17.3
56	Apparel and Accessory Stores	30.2	2.4	32.6
57	Home Furniture, Furnishings, and Equipment Stores	29.9	5.5	35.4

<b>SIC Code</b>	<b>Description</b>	<b>EDRP/SCR Capacity (MW)</b>	<b>Energy/ Ancillary Services Capacity (MW)</b>	<b>Total (MW)</b>
58	Eating and Drinking Places	66.3	10.6	76.9
59	Miscellaneous Retail	29.2	8.5	37.7
60	Depository Institutions	18.2	16.9	35.1
61	Nondepository Credit Institutions	5.8	1.7	7.5
62	Security and Commodity Brokers, Dealers, Exchanges, and Services	40.9	7.1	48.0
63	Insurance Carriers	4.4	0.0	4.4
64	Insurance Agents, Brokers, and Service	32.2	6.8	38.9
65	Real Estate	21.6	4.7	26.3
67	Holding and Other Investment Offices	6.9	0.7	7.6
70	Hotels, Rooming Houses, Camps, and Other Lodging Places	22.4	3.3	25.7
72	Personal Services	12.7	5.0	17.7
73	Business Services	104.8	21.1	125.9
75	Automotive Repair, Services, and Parking	3.5	1.0	4.5
76	Miscellaneous Repair Services	0.9	0.0	0.9
78	Motion Pictures	6.8	2.6	9.4
79	Amusement and Recreation Services	25.9	4.9	30.7
80	Health Services	175.3	57.0	232.3
81	Legal Services	70.3	37.4	107.7
82	Educational Services	322.9	75.6	398.5
83	Social Services	62.3	14.8	77.1
84	Museums, Art Galleries, and Botanical and Zoological Gardens	3.3	5.1	8.4
86	Membership Organizations	21.6	7.9	29.5
87	Engineering, Accounting, Research, Management, and Related Services	56.3	10.7	67.0
89	Actuaries	1.1	0.0	1.1
91	Executive, Legislative, and General Government	12.2	2.8	15.0
92	Justice, Public Order, and Safety	38.8	2.4	41.2
93	Public Finance, Taxation, and Monetary Policy	0.5	0.0	0.5
94	Administration of Human Resource Programs	5.0	1.8	6.8
95	Administration of Environmental Quality and Housing Programs	9.8	1.9	11.8

SIC Code	Description	EDRP/SCR Capacity (MW)	Energy/ Ancillary Services Capacity (MW)	Total (MW)
96	Administration of Economic Programs	6.8	1.1	7.8
97	National Security and International Affairs	1.1	0.0	1.1
99	Nonclassifiable Establishments	60.4	3.8	64.2
<b>TOTAL</b>		<b>1,869</b>	<b>468</b>	<b>2,338</b>

As shown in Table 5, there is a technical potential of 2,338 MW of curtailment in New York State. This represents approximately 65% of the 3,582 MW of total DG capacity. Most of this, 1,869 MW, is eligible for the NYISO EDRP and SCR programs. The balance, 468 MW, would be eligible for energy and ancillary services markets. Clearly, the stock of backup generators in New York is heavily weighted toward the NYISO emergency programs.

It should be noted that the technical potential does not represent the capacity that can be developed. Clearly, the economics of the NYISO markets will drive this. For example, the Energy and ICAP market prices in New York City and Long Island are significantly higher than those in the rest of the state. When one considers the full cost of participating in these markets—including metering, environmental permitting, and opportunity costs (such as the diversion of staff time to the operation of generators, reduced reliability of generators, and shorter service life of generators)—the incentives in areas other than NYISO zones J (New York City) and K (Long Island) may not be sufficient to bring these resources into the marketplace.

## 2.3 Preliminary Costs and Benefits Analysis

After DG resources and suitable energy markets in New York State were identified, the potential benefits were evaluated. An understanding of these benefits was necessary to confirm design specs for the DG aggregation system and determine the required capital and operations and maintenance (O&M) costs to keep the system profitable. These analyses were conducted during 2001 and 2002, when the general design of the system was still in development. Therefore, some assumptions on capital, implementation, and O&M costs were used. As shown in later sections (see Section 6.1), these assumptions were not far from actual costs.

### 2.3.1 Installed Capacity and Energy Market Prices

NYISO capacity and energy prices, as well as the curtailment credit from LIPA, are key determinants of the economic performance of DG. For participating DG resources, there are two NYISO markets: the ICAP Market and the EDRP. In some cases, bill credits may also be available from LIPA under its Peak Reduction Program. These programs were summarized in Section 2.1.

Participating generators will be registered and certified as SCRs for the ICAP Market to be dispatched during system reserve deficiencies. SCRs participate in the ICAP/UCAP markets of the NYISO in accordance with rules detailed in the NYISO ICAP Manual [3]. There are two revenue streams for these DG resources: one for capacity and one for energy provided during EDRP events. In this section, historical capacity and energy prices for Long Island are presented.

The ICAP Market in New York has been operating since the winter 1999–2000 capability period. The periods evaluated here are the three 6-month planning periods from the winter 2000–2001 capability period (November 2000–April 2001) through and including the winter 2001–2002 capability period (November 2001–April 2002).

The ICAP Market has evolved into three capacity auctions: the 6-month strip auction, six monthly auctions, and, if necessary, six deficiency or spot auctions. Historical data for each of these ICAP auctions will be summarized here.

The EDRP came into existence in the summer 2001 capability period. For this report, the evaluation period is for the summer 2001 and winter 2001–2002 capability periods. During this period, the program was invoked 4 days: Aug. 7–10, 2001.

#### 2.3.1.1 Capacity Prices

As described earlier, the NYISO ICAP Market has three auctions: the Strip Auction, the Monthly Auction, and the Deficiency Auction. For Long Island, market behavior was puzzling. In a 15-month period, there was no capacity sold in the Strip Auction for Long Island. In fact, it was only in the winter 2001–2002 capability period that any capacity was transacted in the Monthly Auction—and only for the period of November 2001 through January 2002. Figure 3 shows the volume and price of capacity sold in the NYISO Monthly ICAP Auction.

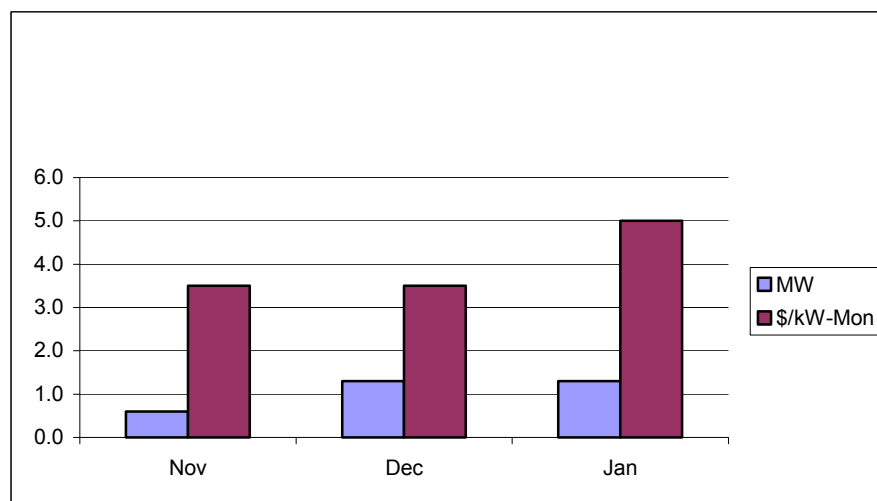
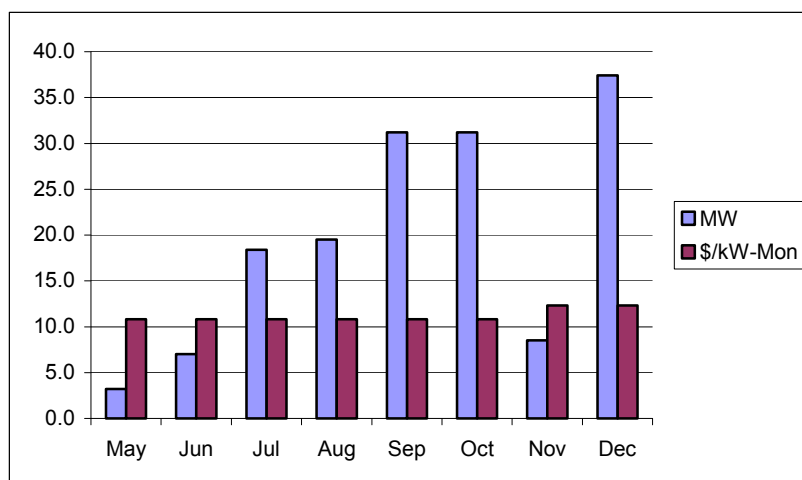


Figure 3. Winter 2001–2002 capability period Monthly Auction for Long Island

In the Deficiency Auction, there was much more activity. Transactions took place since May 2001. Capacity was purchased every month since in quantities that significantly exceeded the volumes in the Monthly Auctions. Figure 4 shows the price and volume of transactions in the NYISO ICAP Deficiency Market.



**Figure 4. 2001 Deficiency Market Auction for Long Island**

As shown by a comparison of monthly and deficiency volumes, more capacity is sold in Deficiency Auctions than Monthly Auctions. The average volume for all months in the Monthly Auctions is 1 MW; in the Deficiency Auctions, the monthly volume averaged 19.6 MW.

Prices are higher in Deficiency Auctions as well. In Monthly Auctions, the average price was \$4/kW-Month; in Deficiency Auctions, the average price was \$11.21/kW-Month. It is peculiar that most of the capacity is purchased in the higher-priced Deficiency Auctions.

### **2.3.1.2 Energy Prices**

The NYISO energy market has 11 zones, and energy prices are calculated for each zone. This locational diversity reflects the varied conditions of the transmission system (with transmission congestion explicitly considered in the locational prices) and the regional diversity of generation.

There are two markets for energy in New York State. These are the DAM and the RT Market. DAM prices are determined on a daily basis for each hour. RT prices are determined in the Balancing Market Evaluation, which is an ongoing process. Typically, RT prices are calculated every 3–8 minutes.

During the evaluation period, the EDRP reimbursement rate for curtailment was the greater of the RT locational-based marginal price or \$500/MWh. Because load data are hourly and RT prices are not, the price floor of \$500/MWh was used as a conservative lower bound in the calculation of EDRP revenues.

The DAM energy price files available from the NYISO include all zones. Long Island (Zone K) prices were extracted and compiled into annual hourly price files. Zone K is the location of the proposed generators, and it is characterized by heavy loading and high levels of congestion during the summer months. In general, Long Island prices tend to be among the highest in New York State.

### **2.3.2 Distributed Generation Resources for Preliminary Analysis**

The preliminary analysis was conducted before project implementation. With the results of the DG resources survey, Electrotek found specific tendencies in its profiling of the DG opportunities on Long Island. For this task, two technology-site configurations were considered. These configurations account for the majority of eligible DG on Long Island. Although there are always site-specific variances, the operational performances of these prototypical technology-site configurations allows for characterization that can readily be adapted for site-specific variances.

The preponderance of existing backup generators on Long Island is either diesel-fired reciprocating engines or combustion turbines. Each of these has technology- and site-specific costs and performance characteristics. In this analysis, two prototypical generator-site configurations are used to estimate the technical and economic performance of aggregated DG on Long Island. These are:

- Two 750-kW turbine generators
- Two 300-kW diesel generators.

For turbine sites, the prototypical participant has two 750-kW turbine generators. The curtailable load is 800 KW, which means that during curtailments both generators operate. This site is typical of a location that needs backup generation with or without redundancy.

For diesel sites, the prototypical participant has two 300-kW generators with a total curtailment of 400 kW. Thus, during curtailment both generators operate. This again is a site with or without redundancy. Table 6 provides a summary of the prototypical sites.

**Table 6. Site Profiles**

	<b>Two 750-kW Turbine Generators</b>	<b>Two 300-kW Diesel Generators</b>
Metering Costs (\$/site)	17,500	17,500
Environmental Permitting Cost (\$/site)	10,000	2,000
Generating Cost (\$/MWh)	35.00	60.00
Curtailable Load (MW)	0.8	0.4
Installation, Testing, and Start-Up (\$/site)	15,000	15,000
Communication	500	500
Total Capital and Installation Cost	\$43,000	\$35,000

As shown in Table 6, each turbine site would cost \$43,000 to bring to market, and each diesel site would cost \$35,000. This includes the installation and configuration of all metering for the location (including the Signature System<sup>TM</sup> to allow operation with the Aggregation and Dispatch Center) and billing meters, in compliance with NYISO metering requirements. Environmental costs assume registering the site for either a State Facility Permit or an Air Facility Registration Permit with the NYDEC for the turbines. The diesel sites would obtain Air Facility Registration Permits.

On a unit-megawatt basis, however, the cost is more favorable for the larger site. The capital and installation cost for the turbine site is \$53,750/MW; for the diesel site, the cost is \$87,500/MW.

In addition, each of the DG resources will be connected to the Electrotek System Aggregation Center. This system, detailed in Section 4, interacts in the NYISO markets, monitors and dispatches the DG in accordance with site-specific notification protocols, and provides all data necessary for the settlement of NYISO accounts. This system includes hardware and software along with networking and communications platforms to work with the Signature System.

### **2.3.3 Market Evaluation**

To evaluate the economic viability of aggregated DG on Long Island, a series of site portfolios was evaluated. These portfolios contained different amounts of turbine and diesel generating capacity in a 30-MW total. The cost and performance characteristics of the diesel and turbine generator sites are reflected in three portfolios. These are:

- Portfolio 1: 15-MW turbine/15-MW diesel
- Portfolio 2: 12-MW turbine/18-MW diesel
- Portfolio 3: 18-MW turbine/12-MW diesel.

For each of these portfolios, a financial analysis was performed to determine the economics of aggregating and selling this capacity in the NYISO and LIPA for a 1-year period. In this analysis, the revenues of each portfolio were evaluated using the 2001 NYISO prices and curtailment calls. For purposes of EDRP, revenue was assumed to be \$500/MWh, the minimum price paid under the program. In addition, LIPA credits were also calculated.

The financial analysis considered all capital and operating costs and revenues for a 1-year period. In additional years, costs will be significantly reduced because of the expense of capital, metering, and installation in the first year. Although subsequent years may offer substantial opportunities, the timing and location of future capacity and the effect of these capacity additions on prices are not precisely known.

Each portfolio was evaluated for 25 hours of EDRP curtailment in a single month. Assuming curtailment under the LIPA Peak Reduction Program for the same period, one month of LIPA credits were also available. A central assumption to this analysis was that all DG sites fully provide their nominated curtailment. In the event of partial performance, significant NYISO penalties are incurred. Deficiency penalties might also be incurred.

Table 7 presents a summary of the three portfolios. Total revenue is the same for all portfolios: approximately \$2.5 million. Costs, however, are primarily driven by metering and aggregation. Operating costs account for 10% or less of the total cost. The greater the number of sites, the greater the total cost. The turbine generator sites are more favorable because they cost less per megawatt for metering and aggregation and they have a lower generating cost than the diesels. Portfolios with a greater weighting toward turbine generators are more profitable.

**Table 7. One-Year Financial Summary**

	<b>Portfolio 1: 15-MW Turbine/ 15-MW Diesel</b>	<b>Portfolio 2: 12-MW Turbine/ 18-MW Diesel</b>	<b>Portfolio 3: 18-MW Turbine/ 12-MW Diesel</b>
Sites	57 sites 19 turbine, 38 diesel	60 sites 15 turbine, 45 diesel	53 sites 23 turbine, 30 diesel
ICAP Revenue	\$2,159,940	\$2,159,940	\$2,159,940
EDRP Revenue	\$375,000	\$375,000	\$375,000
Total Revenue	\$2,534,940	\$2,534,940	\$2,534,940
Total Cost	\$2,489,375	\$2,592,500	\$2,386,250
Net Revenue	\$45,565	-\$57,560	\$148,690

Two of the three portfolios had positive net income in the first year. Portfolio 2 (12-MW turbine/18-MW diesel) had a loss of almost \$58,000. The greatest net income, from Portfolio 3, is nearly \$150,000 in the first year. All portfolios would be profitable in a subsequent year, with all of the capital and installation costs already recovered. Net income could be conservatively expected to increase by \$1 million using the same ICAP and EDRP prices.

## **3 Aggregation System Design and Development**

### **3.1 Background**

The aggregation of multiple distributed generators into a virtual power plant requires a system with the ability to control and monitor generators remotely and provide energy and ancillary services in a competitive energy market. These generators are not normally tracked by the NYISO because of their small individual capacities. But, when combined into a virtual power plant, these generators can be treated as a single central generator. This is given a point identification number (PTID) and modeled and scheduled as a single generator with the ability to participate in the DAM.

A DG aggregation system has to perform three activities:

- Monitor the status of participating backup generators
- Dispatch units remotely
- Conduct transactions with the NYISO.

To perform these activities, the DG aggregation system should include at least:

1. Control and monitoring equipment installed on DG units
2. A central dispatch center for the collection of information and dispatch of generators
3. Communications links for:
  - Transferring information from field generators to the control center
  - Remote control of generators from the control center
  - Communication with the NYISO and other involved parties.

Based on these general requirements, the DG aggregation system architecture was developed. This architecture includes two essential elements: (1) the physical/logical design of the entire system and its components and (b) information flow among system components and between the system and outside counterparts (clients, energy markets, etc.). These elements were under continuous development during the first 2 years of the project. During the project life, many requirements for hardware and software were re-evaluated and adjusted to improve the process and account for changes in energy markets.

A brief history and the final system architecture and components are described in the this section.

### **3.2 Technical Requirements for an Aggregation System and Its Components**

Several sets of technical requirements for the DG Aggregation System were identified for development of the system architecture. These addressed:

- Equipment necessary for control and monitoring of generators
- Energy metering equipment
- Data collection, transferring, and presentation
- Environmental permitting of generators.

These requirements are described in detail below.

### **3.2.1 Equipment for Control and Monitoring of Generators**

This equipment should provide dispatch and remote monitoring of generators and meet the following requirements:

- Control equipment must ensure that the generators can be dispatched, protected from external faults, and isolated from the utility system if the system fails and ensure that the utility system is protected from a fault in the backup generator
- Backup generators must be operational within a certain time (to be determined by the NYISO) in case of a declared NYISO system emergency without affecting availability for local emergency service.
- Control equipment should provide for remote start/stop of generators if the owner permits operation of its generators in such a manner.

According to these requirements, the control system should be able to remotely test an engine, start and run an engine, provide remote transfer of power to and from utility power, and automatically shut down an engine (emergency stop) on selected alarm and pre-alarm conditions. Access to the control system should be via Internet using a cable or digital subscriber line connection and TCP/IP protocol.

### **3.2.2 Metering Equipment**

NYISO settlement data must be provided by a public service commission-certified meter service provider or meter data service provider using billing-certified meters. Certification is provided by the New York Public Service Commission. In addition, settlement data must be hourly interval energy consumption.

This meant Electrotek was unable to use meters it installed for settlement purposes. Nonetheless, a New York Public Service Commission-certified billing meter was selected for installation on some of the DG units. The selected billing meter was a GE kV meter, which provides a local display as well as a pulse output for remote monitoring.

### **3.2.3 Data Collection, Transfer, and Presentation**

Data collected by monitoring equipment should include:

- Engine run status
- Engine run hours
- Engine load status
- Transfer switch status (normal/emergency position)
- Building load status (when on commercial power).

This information should be collected and available for presentation on live and historic bases (in forms of tables or graphs) via the Internet to a system aggregator, a generator owner, and the NYISO.

### **3.2.4 Environmental Permitting of Generators**

The system aggregator should ensure all generators are properly permitted with the NYDEC to operate for commercial purposes. Most backup generators available for aggregation will need a minor facility registration or a state facility permit.

### **3.3 Distributed Generation Aggregation System General Design and Main Components**

The DG aggregation system includes three entities: the Data Collection and Management Center, the Aggregation and Dispatch Center (ADC), and the Field Operation, which includes all participating buildings. Each entity includes several operations modules interconnected via Internet and other communication media.

The decision to distribute management and operation activities between two locations was based on the following:

- Operation of the virtual power plant requires powerful servers and computer stations to collect, store, and manage large amounts of data. Electrotek had this equipment available at its Knoxville, Tennessee, office. In addition, personnel experienced in data management, software development, and system operations were located here. These factors drove the decision to locate the DMC in Knoxville.
- The proximity of World Power Technologies<sup>1</sup> headquarters to New York and Long Island and World Power Technologies' staff of experienced electronic/computer engineers and technicians needed to support field operations made it the logical choice for the ADC.
- The Web-based application AggregationWeb provides a single point of access to system information for all users (clients, the NYISO, and ADC staff). The physical location of system components is immaterial.

#### **3.3.1 Distributed Generation Aggregation System Architecture**

The DG aggregation system architecture includes two elements:

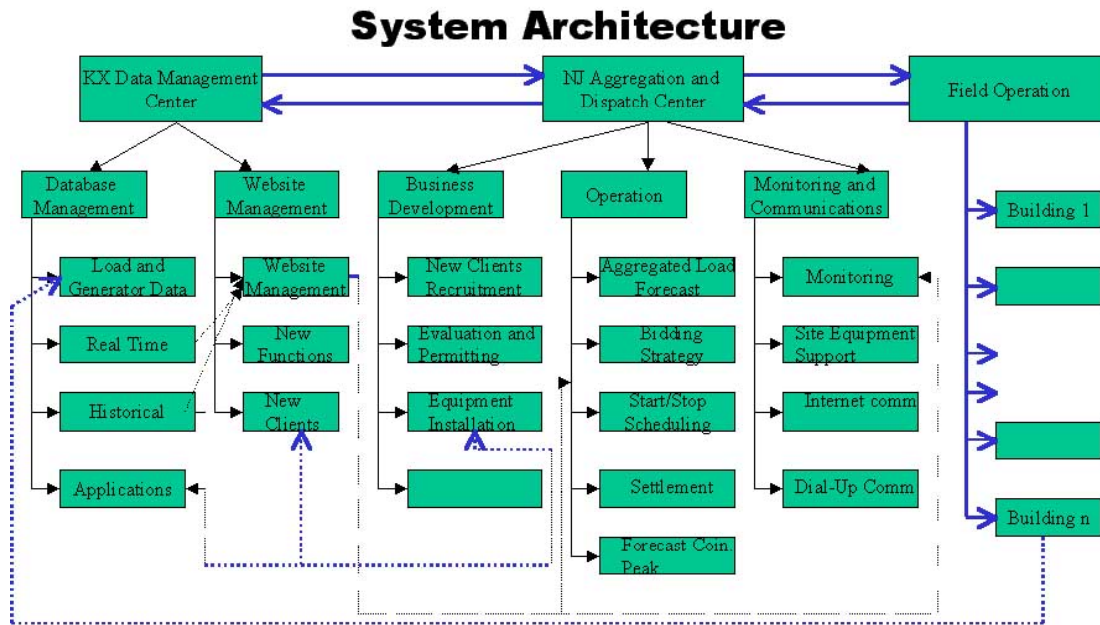
1. The physical/logical design of the system and its components
2. The information flow among system components and between the system and its outside counterparts (such as clients and energy markets).

##### **3.3.1.1 Physical/Logical Design of the Distributed Generation Aggregation System**

The architecture of the DG aggregation system is presented in Figure 5.

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<sup>1</sup> World Power Technologies is the parent company of Electrotek Concepts, Inc. It is located in Edison, New Jersey.



**Figure 5. Distributed generation aggregation system**

The major components of the DG aggregation system are:

- **Field Operation**

The Field Operation aggregates multiple backup generators, which could be located in different buildings around the New York, Long Island, and Westchester County areas. The system includes more than 50 generators, and the aggregation system is designed to incorporate additional generators as necessary. Major duties of the Field Operation are:

- Power generation
- Monitoring of generators
- Data collection.

- **Data Collection and Management Center**

The DMC is the central location for the collection and management of information necessary for the operation of the DG aggregation system. It is located in Knoxville, Tennessee. DMC's main duties include:

- The collection and storage of information about the activities at Field Operation, energy market pricing and load forecasts, and forecasted and historical weather data
- The development and maintenance of the DG aggregation Web site
- The development and maintenance of new software necessary for the operation and expansion of the DG aggregation system.

- **Aggregation and Dispatch Center**

The ADC is the central point of operation of the DG aggregation system and includes three divisions: Operations, Business Development, and Monitoring and Communication.

The responsibilities of these divisions are:

- Operations is responsible for operation strategy, bidding preparation and execution, dispatching and monitoring generators, and settlement and accounting procedures.
- Business Development is responsible for recruiting new clients, economic and technical site evaluation, permitting, and field equipment installation and start-up.
- Monitoring and Communication is responsible for the support and maintenance of field monitoring equipment and all communication channels (Internet, dial-up, pagers, etc.).

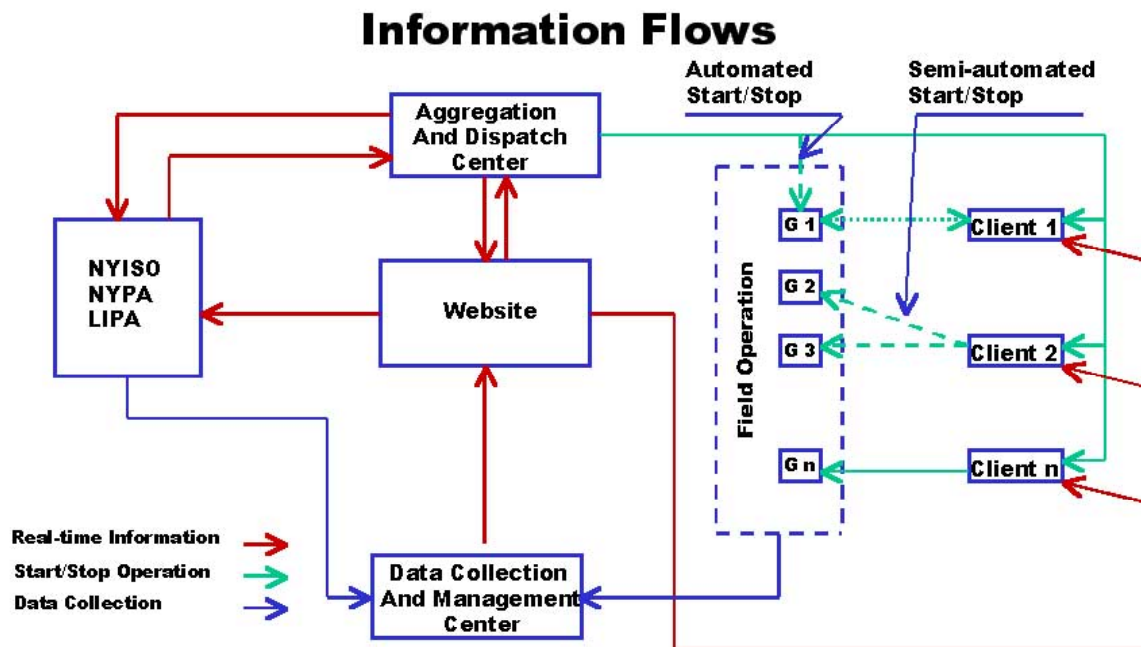


Figure 6. Information flow in distributed generation aggregation system

### **3.3.1.2 Information Flow**

The design of information flow among system components and between the system and outside counterparts is presented in Figure 6. Details of the flow include:

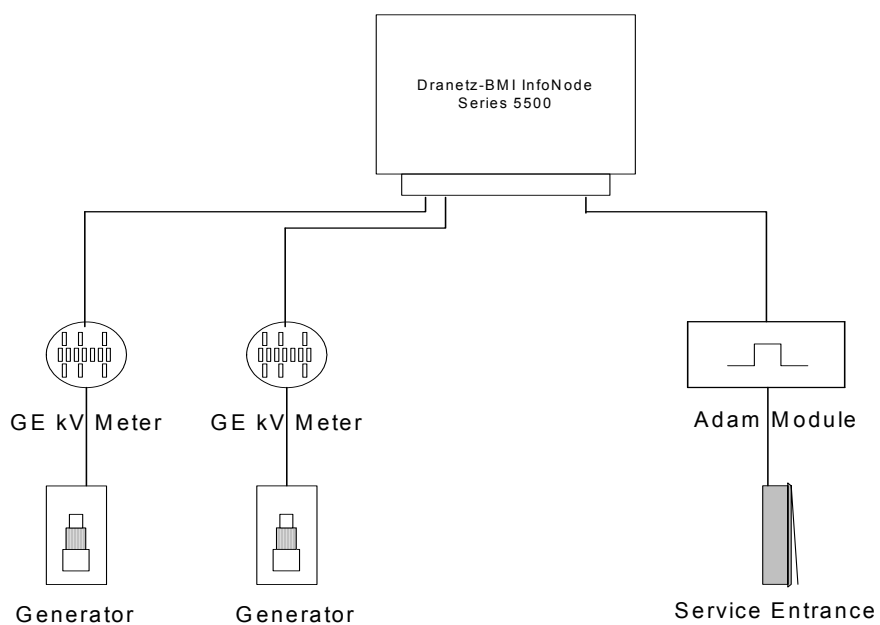
- The central point of access for system information is the DG aggregation Web site, AggregationWeb. This Web site provides access to live and historical events. It is the interface for the ADC and external users (i.e., clients, the NYISO, and LIPA). It is also the interface of all computer tools necessary for normal DG aggregation system operation. These tools include the bidding/dispatch tool, the settlement and accounting tool, the coincident peak-hunting tool, and the economic evaluation tool. A detailed description of the aggregation Web page is provided in [4].
- Data collected at generation sites are downloaded to the DMC via digital subscriber lines or dial-up telephone lines.
- The ADC is responsible for issuing the engine start/stop commands. There are several mechanisms for issuing these commands: an automated engine start/stop, a semi-automated engine start/stop, and a manual engine start/stop.
  - The automated engine start/stop requires a direct connection (leased line) between the ADC and the client's control system.
  - For the semi-automated engine start/stop, the ADC contacts the client's area managers, who remotely start/stop multiple engines on site.
  - For the manual engine start/stop, the ADC contacts client on-site personnel with a request to start or stop engines.
- ADC contacts the NYISO, LIPA, the New York Power Authority, and other power authorities and power markets via telephone and Internet for bidding and settlement operations.
- DMC downloads load forecast and market prices from the NYISO.

Details of these information pathways will be provided in relevant sections of this report.

### **3.3.2 Field Operation**

Client sites may differ in terms of engine type and size as well as building electric system design. However, all sites have three major components: the power generation equipment, the power monitoring equipment, and the data collection and transmission equipment. Only the last two components are designed, installed, and maintained by the DG aggregator (Electrotek Concepts Inc.). The design of these components is based on the Signature System, developed by World Power Technologies and Electrotek Concepts Inc. The Signature System is an integrated, Web-based platform that incorporates multiple measuring and monitoring instruments called DataNodes<sup>®</sup> that report to a gateway/Web server called an InfoNode<sup>®</sup>.

A typical design of the on-site instrumentation necessary for DG aggregation is presented in Figure 7. Figure 8 shows the monitoring equipment installed at a site on Long Island.



**Figure 7. Monitoring equipment**



**Figure 8. Installed monitoring equipment**

### **3.3.2.1 Power Generating Equipment**

Power generating equipment for backup emergency power is typically provided by diesel engine or gas turbine. This equipment belongs to and is maintained by the client. Some clients prohibit the DG aggregator from having direct access to their control systems. In these cases, the DG aggregator cannot control the generators in a completely automated fashion and therefore operates them through client-authorized personnel. Nevertheless, the DG aggregator should have intimate knowledge of these generators and the capability to track key characteristics such as engine reliability and availability, engine fuel consumption, and the curtailable load of the building.

- Engine reliability and availability are important because bidding and dispatch procedures for participation in the energy market are based on the creation of groups of multiple engines with a total capacity reported to the independent system operator (ISO). A failure of a single engine during the operation could result in financial penalties.
- Fuel cost represents a significant part of the cost of electricity generated by DG. Therefore, precise calculation of the fuel consumed by each engine is important for the bidding strategy.
- The curtailable load of a building is the maximum load that may be transferred to the generators. Very often, the installed capacity of emergency generators is bigger than the entire building's maximum load. Also, in some buildings, the entire electrical load is separated for essential and nonessential load, and only essential load is automatically transferred to emergency generators during a commercial power failure. Therefore, it is the curtailable load that is of interest to the DG aggregator, not the capacity of the installed generators.

For successful operation of the DG aggregation system, it is necessary to forecast both building load and relevant fuel consumption.

### **3.3.2.2 Monitoring Equipment**

It is advisable to monitor two points at any DG generation site: power output from the generator(s) and energy flow at the commercial power service entrance(s). These functions are performed at any DG site by different instruments. These are used in the system architecture under the generic name "DataNode" [5].

#### **3.3.2.2.1 GE kV Meter DataNode**

An energy revenue meter measures power output from the generator. The GE kV meter was selected as a standard generator output DataNode. The DG operation uses the following quantities collected by the GE kV meter:

- Phase energy (watt hours)
- Phase peak active power demand
- Phase "instantaneous" active power
- Phase voltages
- Phase currents.

#### **3.3.2.2.2 Advantech® ADAM Module**

Unfortunately, meters installed at generators could not be used for settlement with power market and power authorities such as the NYISO and LIPA. These authorities allow only measurements made by meters installed and operated by certified metering companies be used for energy sales transactions. These meters are installed on commercial power services and operated by energy supply companies. To obtain the information necessary for the DG aggregation operation, the DG aggregator should have access to the information collected by these meters. This role is performed by another type of DataNode: an ADAM Module.

The ADAM Module is a pulse counter that measures the building load at the electrical service entrance. The energy meters that the electric utilities have in place have KYZ pulse output. This is a “demarcation box”—a unit that permits Electrotek to have output from the utility’s revenue meter in the form of “pulses.” For every so many kilowatt-hours measured, a set of relay contacts is “pulsed.” The pulse multiplier is the number of kilowatt-hours per pulse and is individually set for each site. From the other side, the demarcation box prevents Electrotek from interfering with the operation of the utility-installed revenue meter. The ADAM Module is able to detect the pulse and increment its counter. The pulse multiplier for each meter is then used to convert pulses to energy.

#### **3.3.2.3 On-Site Data Gateway**

The Dranetz-BMI InfoNode 5500 is the gateway between the DataNodes and the DMC. The features of the InfoNode are:

- **Data Collection**  
The InfoNode is the data concentrator for the data collected by the GE kV meters and ADAM Modules. It is also the interface for downloading data to the DMC.
- **Remote Setup of DataNodes**  
The InfoNode provides a Web interface for setting up the DataNodes, GE kV meters, and ADAM Modules. Through this interface, the DataNodes are named, channels are selected, and storage intervals are set.
- **Live Data Interface**  
The InfoNode has a live data interface that allows clients to get 10-second updates of voltage, current, and power quantities.

For detailed specifications of the Signature System InfoNode 5500, see [5].

### **3.3.3 Data Collection and Management Center**

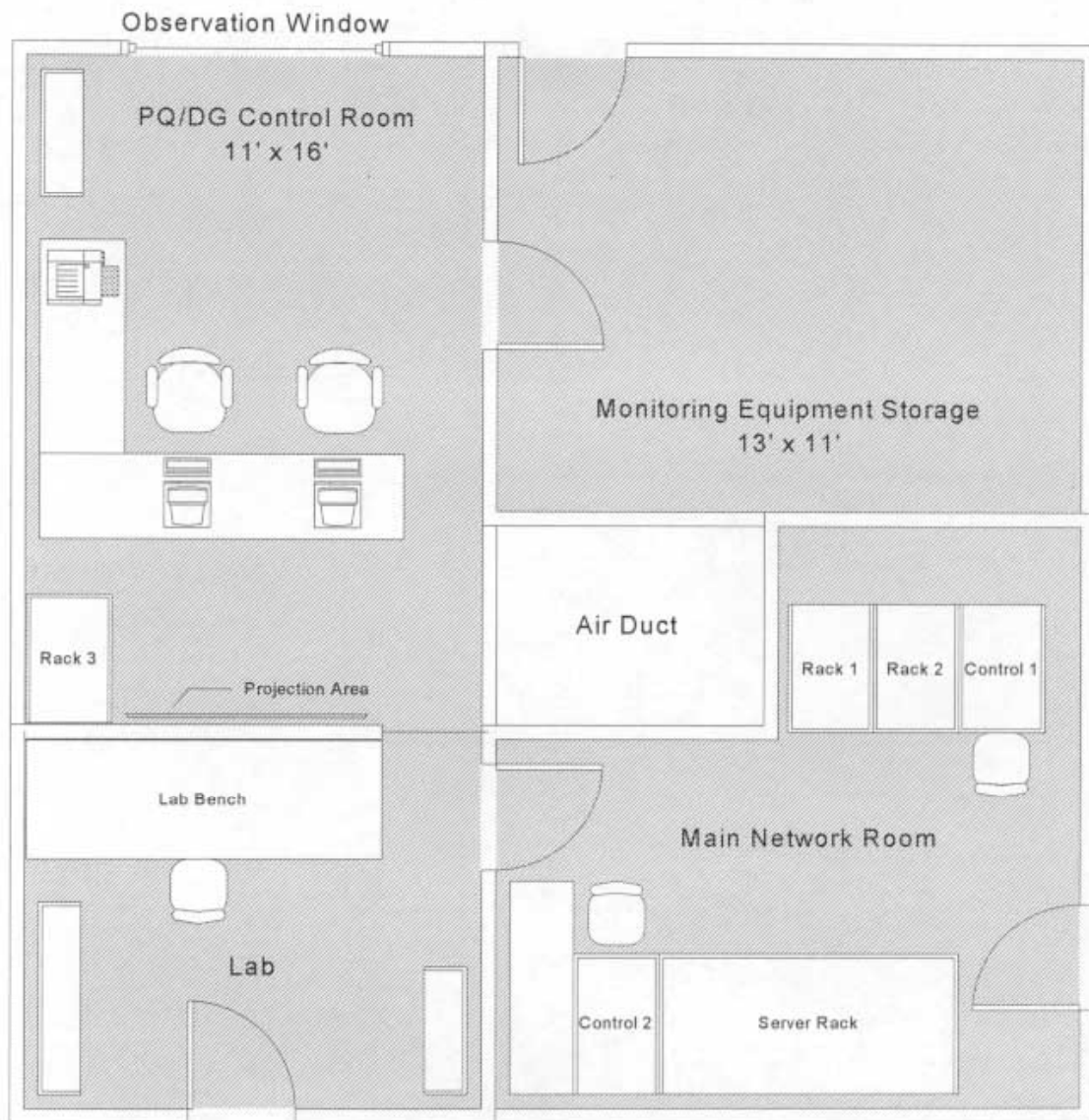
Servers and workstations comprise the DMC. The storage capacity of the Dranetz-BMI InfoNode 5500 located at the generation site is limited, and it is not designed for long-term data storage.

This section contains descriptions of the physical design, equipment, and tools of the DMC.

### 3.3.3.1 Physical Design and System Architecture of the Data Collection and Management Center

The physical layout of the DMC is shown in Figure 9, and the DMC central room with computers and projection screen is presented in Figure 10.

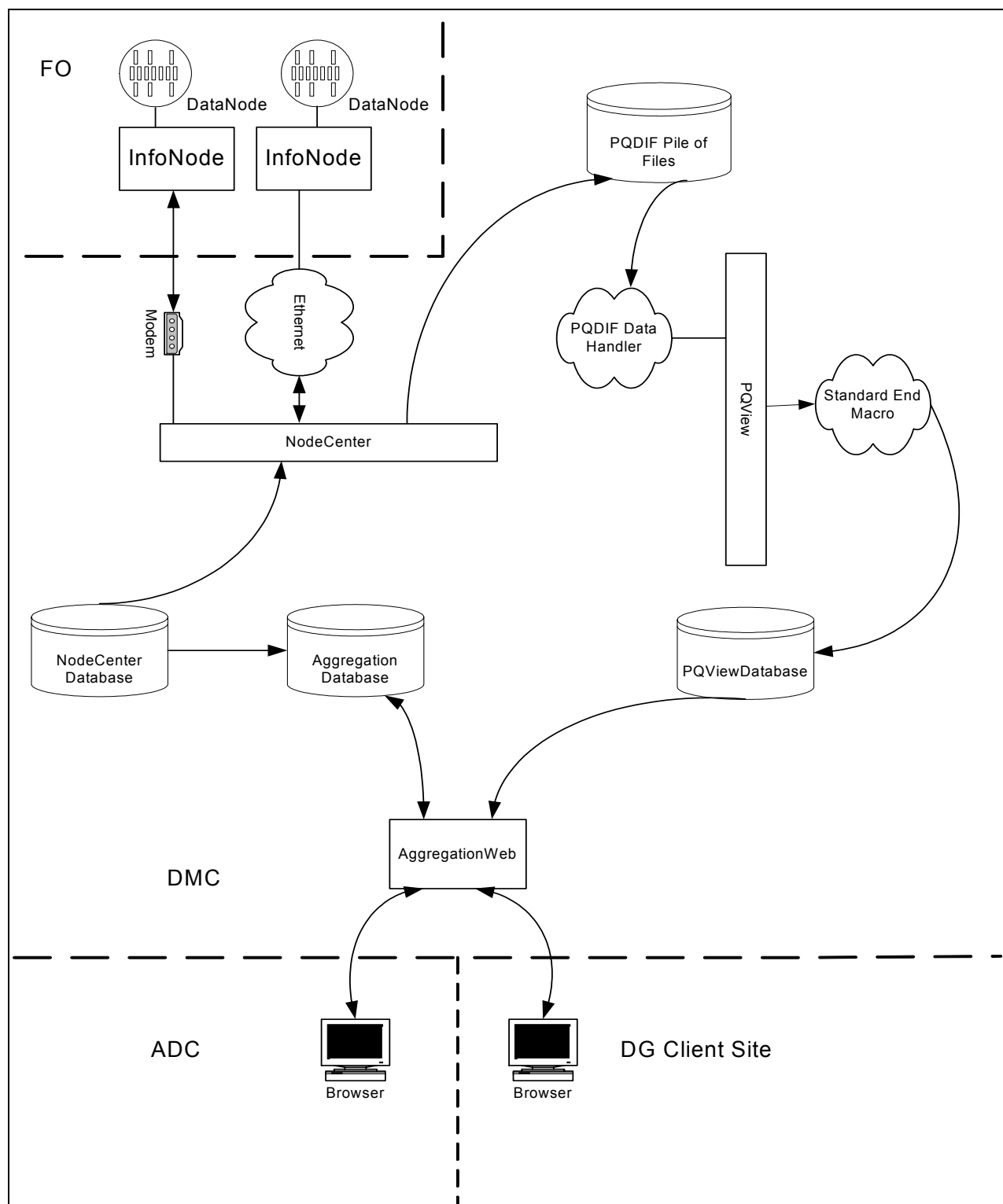
The system architecture of the DMC is depicted in Figure 11. The system architecture of the DMC can be broken down into two major areas: server components and user tools.



**Figure 9. Physical layout of the Data Collection and Management Center**



**Figure 10. The Data Collection and Management Center**



**Figure 11. Distributed generation aggregation system architecture**

### **3.3.3.1.1 Server Components**

There are two main subsystems: NodeCenter and PQView. A brief description of these subsystems is provided below. Both subsystems are discussed in detail in [5].

#### **NodeCenter**

NodeCenter is the enterprise software of the Signature System. The NodeCenter software runs on a Microsoft® Windows 2000 server. NodeCenter is the system that downloads the data from multiple InfoNodes. The capabilities of the NodeCenter software will be discussed as they pertain to the DG operation. The two main components of NodeCenter are the NodeCenter database and NodeCenter Service. The NodeCenter database is built on the platform of a Microsoft Access database. NodeCenter Service is a service program developed by Electrotek.

#### ***NodeCenter Database***

To contact and download data from the InfoNodes installed at a DG client's site, certain information is required. This information is stored in the NodeCenter database. Below is a list of fields required for NodeCenter to perform the download function. Any restrictions or requirements stated here are not necessarily inherent to NodeCenter but have been imposed by the DG operation.

1. Downloadable instrument  
This corresponds to an InfoNode. A downloadable instrument requires a name and an IP address.
2. Site  
This is a grouping of downloadable instruments. For the DG operation, this is a one-to-one mapping. One site corresponds to one downloadable instrument.
3. Monitor  
This corresponds to a DataNode (i.e., a GE kV revenue meter or an ADAM Module). Each DataNode has an InfoNode as a parent.
4. Download group  
This is a group of monitors with data to be downloaded.
5. Schedule  
A schedule specifies the time and frequency of a download for a download group.

#### ***NodeCenter Service***

NodeCenter Service is started automatically when the server boots up. At start-up, NodeCenter Service loads the information described above. NodeCenter Service is responsible for downloading the data based on the schedule and download groups in the database. NodeCenter Service logs all stages of the download and handles retries and queuing of the download requests. If an InfoNode fails to download after all retries, then the technical coordinator alerts the support technicians at the ADC. Data are not generally lost because of download failures. Data are lost only if they are purged from the InfoNode database prior to being downloaded. Otherwise, the data will be downloaded on the next successful attempt.

On the NodeCenter server, there is a PQDIF<sup>2</sup> directory, and all downloaded data are written to this folder. For each InfoNode-DataNode combination, a subdirectory is created, and the data for that pair are written in files using the PQDIF format.

### **PQView®**

PQView is a database management system designed to store and analyze large quantities of power quality-related disturbance and steady-state measurement data. The data collected by the DataNodes (GE kV meter and ADAM Module) are steady-state data. Steady-state data are collected on a time interval. The DG operation was able to use this application for the management of data collected at DG client sites. PQView stores the data in one relational database for each DG Client. PQView can be configured to automatically import the PQDIF files that were created by NodeCenter.

#### **3.3.3.1.2 User Tools**

The DMC houses AggregationWeb, which is the user interface to all data and support tools. AggregationWeb is the single interface for all DG operations. It features tools that support all activities at the ADC and data views that are accessible by DG clients.

### **Distributed Generation Operation Tools**

The ADC must perform many activities. There are setup activities as DG clients are added to the system, and there are daily activities, activities when curtailments occur, and monthly activities for settlement. AggregationWeb provides the tools to perform these activities.

### **Distributed Generation Client Management Tools**

AggregationWeb provides setup tools for adding new DG clients to the system. For each client, there is an interface for entering address, contact, user, and contract information. In addition, the control operator may enter all buildings participating in the operation of each client. The buildings are linked to the NodeCenter sites. The control operator may enter information about each generator.

The use of this tool is described in detail in the AggregationWeb Manual [4].

### **Operation of Generators**

Generators are operated anytime the ADC has been notified to run the generators it is managing. A call to run may be the result of a bid being accepted in the DAM, or it may be a call from the EDRP or another energy program. The running of generators in response to any call is entered in the aggregation database as a curtailment.<sup>3</sup> AggregationWeb is the interface for creating the curtailment. Curtailments are used to track generator runs and estimate revenue. The details of a curtailment procedure are described in [4].

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<sup>2</sup> PQDIF is an industry standard format for representing power quality data.

<sup>3</sup> Any generation in AggregationWeb is called curtailment because, so far, generators are not interconnected and are dispatched without delivery of any energy back to the grid. Even if a generator is used in an economic program and is paid for energy generation, the building is fully or partially disconnected from the grid and generators are providing the energy to fulfill the building load. In other words, the building load is curtailed from the commercial grid.

To support the operation of the ADC, a library of computer tools, manuals, and guidelines was developed and placed in AggregationWeb. These tools include a bidding tool, a coincident peak-hunting tool, and a building economics evaluation tool.

### **Distributed Generation Client Visualization Tools**

These tools provide views of archived and live data directly from the InfoNode. These tools are available to the ADC and DG clients. The views are:

- Live generation
- Real-time
- Hourly
- Revenue
- Load profile
- Generator run summary.

These views are available through AggregationWeb. Instructions and more detailed discussions of these views can be found in [4].

### **Live Generation**

AggregationWeb has a real-time view with an update rate of 10 seconds. It establishes connections to InfoNodes based on requests received from AggregationWeb clients. The system is designed such that multiple requests to the same InfoNode will only require one connection, and the connection will be maintained as long as requests are made within a predefined time interval. The Web page automatically sends requests as long as the page is displayed to the client. When all clients leave their respective pages, the connection will be dropped after the time-out period has expired. For the hourly view, data are updated every 15 minutes, so it is not necessary to use the proxy cache for this data.

#### **3.3.3.2 Revenue**

Revenue is a curtailment-based view. It provides an estimate of revenue for the DG client based on the curtailments in which it has participated. The client may view monthly revenue or revenue for individual curtailments.

#### **3.3.3.3 Load Profile**

The load profile view provides the DG client with a view of the electrical load at each building service entrance. The interval load data are stored in 5-minute intervals, but the load profile view allows users to aggregate the data into larger intervals prior to display.

#### **3.3.3.4 Generator Run Summary**

The generator run summary provides the DG client with a summary of its generator runs. For each generator, the summary includes the date of run, the length of run, and the average power generated for each hour of operation.

#### **3.3.3.5 Initial Setup**

The DMC consists of multiple subsystems and is managed by a technical coordinator who is responsible for data collection and storage. The technical coordinator must interface with each subsystem for the data collection process of the DG operation to function properly. Duties of the technical coordinator include initial setup, daily activities, and troubleshooting. The initial setup procedure is performed mostly during construction of the DG aggregation system and is described below.

Once the installation of monitoring equipment is complete, certain tasks must be completed to add DG clients to the DG operation:

1. Create a site in the NodeCenter database that corresponds to the Dranetz-BMI InfoNode installed at the DG client site. Add the InfoNode as a downloadable instrument for the site.
2. Perform a health check on the InfoNode from NodeCenter. The health check reports the status of the Dranetz-BMI InfoNode and associated DataNodes. It is through the health check operation that DataNodes are added to the NodeCenter database.
3. Create one or more download groups in NodeCenter for the DG client.
4. Add the download group to a schedule in NodeCenter.
5. Perform an initial manual download.
6. Create a PQView database for the new DG client.
7. Set up automatic steady-state data import with storage in the PQDIF database.
8. Set up configurations for the energy quantities collected at the generators and at the service entrance.

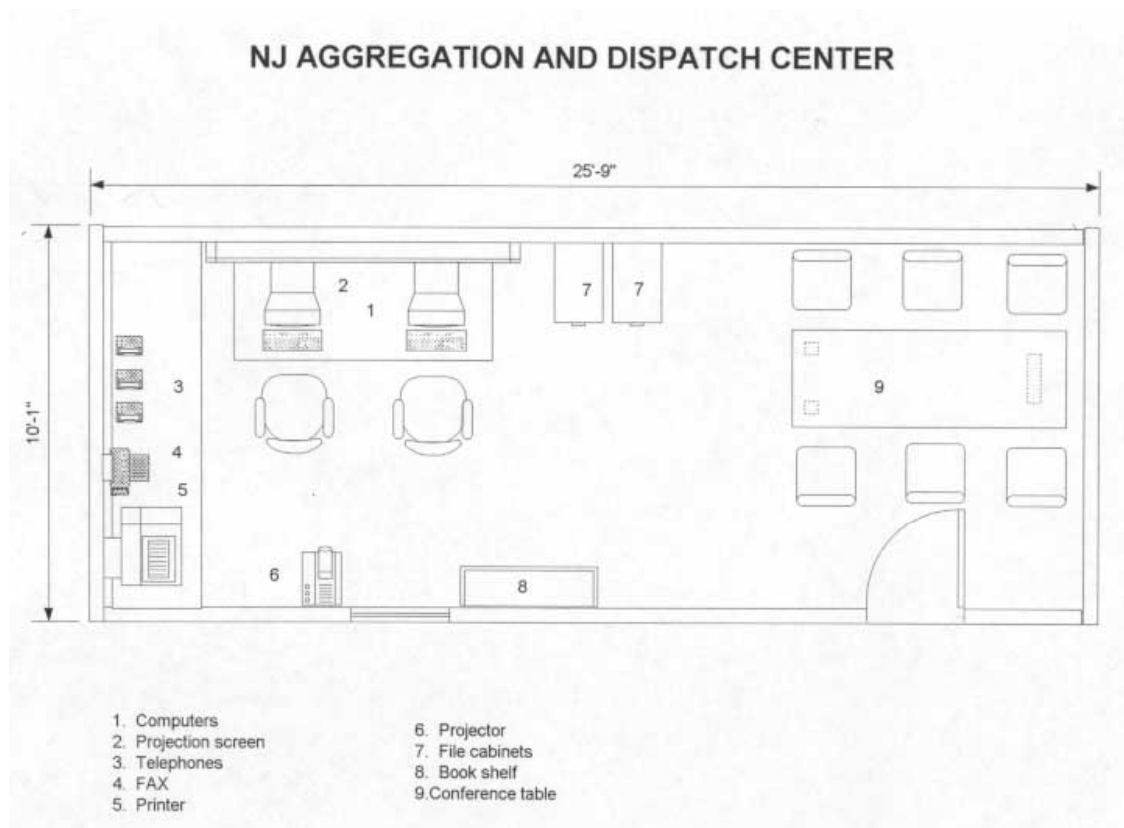
Detailed descriptions of these tasks and a step-by-step procedure can be found in [5], the DMC Operations Manual.

#### **3.3.4 Aggregation and Dispatch Center**

The ADC is the central point of operation of the DG aggregation system. It was built in Edison, New Jersey, and includes three divisions: Business Development, Operations, and Monitoring and Communication. The responsibilities and activities of these divisions are described in this section. To support the activities of the ADC, a library of computer tools, manuals of procedures, and instructions was developed.

##### **3.3.4.1 Physical Design of the Aggregation and Dispatch Center**

The physical design of the control room of the ADC is presented in Figure 12.



**Figure 12. Control room of the Aggregation and Dispatch Center**

### **3.3.4.2 Business Development Division**

The Business Development division is responsible for recruiting new clients and bringing them on as operational resources in the system.

After a potential client is identified, a chain of specific activities is performed. This includes an initial site visit; economic/financial evaluation; environmental permitting; design; equipment procurement, installation, and startup; and certification of installed equipment.

Some facilities may require additional activities such as the installation of fuel flow meters and the implementation of emission reduction technologies.

#### **3.3.4.2.1 The Initial Site Visit**

The objectives of the initial facility site visit are to develop specifications of aggregation equipment, evaluate emergency generator operation, and determine any necessary environmental permitting and emission reduction measures. Detailed guidelines and a questionnaire for the initial visit to a candidate facility are presented in [6].

#### **3.3.4.2.2 Economic and Financial Evaluation**

The objectives of this step are to evaluate whether the facility is a good candidate for participation in a curtailment or energy market program—in other words, whether the operation of this facility for these programs would be profitable for the building owner and aggregator.

A preliminary economic evaluation is conducted using information collected during the initial site visit. This information includes facility location, electricity provider, type of business (industrial, commercial, hospital, etc.), nameplate data on emergency generator(s), summer and winter load data, amount of load curtailable with emergency generators, and existing and necessary environmental permitting issues.

Two other sets of information necessary for economic/financial analysis should be obtained from specialized organizations: the anticipated expenses for testing, maintenance, and repair of generating and switchgear equipment and the cost of the aggregator's equipment installation.

This information is used as inputs for the Building Economic Model, BEM 9.1. The spreadsheet model BEM 9.1 has been developed to examine the financial benefits (or losses) of integration of a new distributed generator into the DG aggregation system. The spreadsheet is written in Microsoft Excel and allows users to perform a number of cash flow analyses to determine the best option for incorporation into the system, including the optimum set of monitoring equipment for revenue.

The model provides the DG owner and aggregator with the following project financial indicators:

- Internal rate of return
- Net present value
- Payback period.

The model calculates the financial indicators for five evaluation periods: 1, 2, 3, 4, and 5 years.

Cash flow analyses are based on estimations of the owner's and aggregator's project development costs, monthly operating expenses, monthly revenues from capacity and electric energy sales, and electric energy savings. The BEM 9.1 User's Manual is presented in [7].

#### **3.3.4.2.3 Environmental Permitting**

To use emergency generators for the load reduction program, a facility should obtain some kind of environmental permit. Information required to obtain these permits includes:

- Type and size of emergency generator
- Type and hourly consumption of fuel
- Diesel/turbine manufacturer's data on NOX, CO, CO2, and particulate matter emissions
- Design parameters of the engine exhaust system.

Very often, emissions are capped per facility, not per engine. Therefore, it is necessary to obtain data on all combustion sources on the premises. These include boilers, hot water heaters, absorption chillers (using natural gas), and other such equipment. Information required for this equipment is similar to that required for generating equipment (see above). In addition, operating schedules and durations of operation should be obtained. This is important for calculation of annual fuel use and annual air emissions release from this equipment.

In some cases, it is necessary to monitor the fuel consumed by emergency generators. This often requires the installation of fuel flow meters or fuel level meters on fuel tanks. Usually, preliminary information obtained before a site visit helps determine if the installation of fuel flow meters is necessary. If so, a detailed evaluation of the fuel handling and supply system is performed to determine the size and type of flow meters needed as well as a suitable place for their installation.

#### **3.3.4.2.4 Equipment Design, Procurement, Installation, and Start-Up**

Electrotek conducts equipment procurement on the basis of design specifications. Installation usually does not require any Electrotek involvement. The exception is cases in which corrections must be made to design specifications according to local conditions.

The final part of this stage of implementation is the start-up of monitoring equipment. This operation requires starting all generators and transferring essential and non-essential facility loads to emergency generators. Quite often, the essential and nonessential facility loads are supervised and operated by different management groups, and good coordination between these groups is essential for successful start-up and future curtailment operations.

#### **3.3.4.3 Operations Division**

The Operations division is responsible for adding information about new customers in the system, their operations strategies, bidding preparation and execution, dispatching and monitoring generators, and settlement and accounting procedures. These activities are performed through the DG aggregation Web site, which contains several tools to support dispatchers in decision-making and operating the DG aggregation system.

This section details the addition of new customers and describes tools developed to support the operation of the DG aggregation system.

##### **3.3.4.3.1 Addition of New Customers**

After a contract with a new customer is signed and on-site monitoring equipment is installed, the customer and his equipment are included in the DG aggregation Web database. This is performed by filling out forms in the setup section of the aggregation Web site.

For each customer, the Web site contains:

- Customer name and location
- Primary contact(s)
- Aggregation Web user information
- Equipment and curtailable load information
- Programs in which the customer will participate.

After that, the new customer's monitors are added to the NodeCenter database and accounting system.

#### **3.3.4.3.2 Support Tools for Distributed Generation Aggregation System Operation**

Although the current project anticipates all aggregated generators will be used simultaneously in a single business economic arrangement, the DG aggregation system is designed with flexibility that permits generators to run for different energy economic programs. It is the responsibility of the Operations Division to determine the best strategy of program participation for each generator or group of generators.

For each program or business model, specific formal procedures (such as filling out applications and preparing and submitting bids) should be followed. However, a common requirement of all programs is that the operator know the amount and cost of energy that can be delivered at any given time from each and all aggregated generators. In other words, the operator should have at his disposal a tool to forecast building/generator load and the cost of electricity generated. The operator should also be prepared to make strategic decisions about whether generators should be operated in attempt to hit the system coincident peak.

##### ***3.3.4.3.2.1 Forecasting Building/Generator Load and Cost of Electricity***

A computer tool was developed to forecast hourly load for each site. The load forecast tool uses a linear regression model based on actual loads, actual hourly temperature and humidity, and forecasted hourly temperature and humidity. Once an hourly load forecast is developed for each site, hourly running costs for each site's generation is calculated.

The first step is to obtain an hourly temperature and humidity forecast for the generator location. These data are usually available from nearby National Weather Service field offices. Given the computational effect of using multiple temperature forecasts and the minor temperature differences among locations, usually only one temperature/humidity forecast (for the central place of the area) is used. For example, for 10 facilities on Long Island, these data were obtained for the Central Islip. The hourly temperature and humidity forecast was obtained over the Internet from a commercial subscription<sup>4</sup> service, the AWIS Weather Services Co., and was updated every 4 hours.

The next step is to forecast hourly loads and calculate running costs by site. This is done in two steps. The load forecast regression model is used to calculate each site's hourly load, and a spreadsheet model is used to calculate each site's hourly running cost. Hourly running costs use forecasted loads and hourly forecasted temperatures. Running costs are based on unit availability, unit fuel and O&M cost, and startup cost. The unit operating cost (fuel plus O&M) is calculated based on site load and temperature for each hour. Given that these units are not expected to operate for periods of more than 6 hours of any day, start-up costs become a significant factor in determining the least-cost dispatch schedule.

Another component necessary for dispatching generators for economic programs is the DAM price. This price is also automatically downloaded from the NYISO Web site daily. The information is then presented on the DG aggregation Web site.

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<sup>4</sup> AWIS Weather Services, located in Auburn, Alabama, can be found on the Internet at <http://www.awis.com>.

The decision to dispatch a generator is made on the basis of a comparison of the cost of electricity and DAM price and consideration of a special set of constraints (such as minimum run time and start-up and shutdown times) associated with each economic model. The bid preparation tool was designed with the flexibility to be used with different business models and strategies. Some of these are described in this report.

#### ***3.3.4.3.2.2 Hunting for Coincident Peak***

The ICAP requirement of an LSE in New York State is based on the collective demand of its aggregated customers (by zone) at the 1-hour system peak in the zone. For summer-peaking zones (all but one in New York State), the coincident peak, by definition, can occur June through September. LSEs are required to meet their ICAP requirement by buying sufficient capacity bilaterally or from the NYISO ICAP Market or by having sufficient generating capacity available. Therefore, if an LSE can reduce its ICAP requirement by curtailing load at the coincident system peak, then its financial commitments for ICAP will be reduced the following capability period.

For most cases, the requirement is computed by estimating the LSE's contribution to system peak based on the collective consumption of its customers relative to the total in their zone. However, an LSE has the option of measuring actual demand at the peak hour and using that measurement to determine next year's ICAP requirement. Therefore, it is acceptable for the generator owner or operator to operate its engines during the LIPA coincident peak. If this is successful, the ICAP requirement will be reduced the following year.

For customers concerned about coincident peak, the challenge is to estimate when this hour of system peak will occur. It would be easy to run engines every time the temperature (or temperature-humidity index) is predicted to be higher than any previous day's. But the generator's owner usually wants to limit operation to minimize the net cost of operation and because NYDEC permits limit the hours each engine can operate.

A computer model, the "Peak Hunting Strategy," was developed with the practical goal of capturing the season coincident peak without activating engines more than 10 hours per month during the peak-hunting season. This strategy helps operators predict:

1. When the first activation should be called at the beginning of the peak season
2. When each subsequent activation should be called.

The program is operated once a day automatically by the aggregation Web site, and it presents its results on the special screen in the form of advice: Run or Not Run generators tomorrow.

A detailed description of this tool is presented in [Ref.8].

#### ***3.3.4.4 Monitoring and Communication Division***

The Monitoring and Communication division is responsible for the reliability of monitoring and communication equipment in the ADC and Field Operation. This includes:

- Preventive and emergency maintenance of telecommunication equipment in the ADC
- Preventive and emergency maintenance of on-site monitoring and telecommunication equipment installed in facilities where aggregated generators are located.

## **4 Operation of the Distributed Generation Aggregation System**

The operation of the DG aggregation system involves a multitude of tasks and activities. Some of these, such as retrieving and downloading data, are conducted automatically, and others involve more direct human intervention. Given the number of participants involved and the multitude of curtailment programs, the proper and efficient management of these resources is a complex procedure.

### **4.1 Data Management Center**

Daily data management of the DG aggregation system involves a number of operations and functions. These functions are performed at the DMC. The DMC is a configuration of servers, workstations, and peripheral devices that collects data from a number of sources, validates them, and loads them into a master database. The DMC also uses these data for other activities, including load forecasting and peak hunting.

DMC activities cover three main areas:

- Data management
- Control of communication and data collection system reliability
- Web site support and maintenance.

Data management and control of communication and data collection system reliability is performed by a data management operator and usually requires 1–3 hours of activities every day. DGEEnterprise Web site support and maintenance is performed by Electrotek's hardware and software engineers and programmers on as-needed basis and usually takes about 10–12 man-days per month.

#### **4.1.1 Data Collection and Management**

The daily operation of DMC data management includes several download operations:

- Site load data from ADAM Modules, which count pulses from the utility service meter to compile hourly loads (daily)
- Interval data from the GE kV meters installed on the generators (daily)
- Hourly temperature and humidity forecasts (four times a day)
- NYISO DAM prices (daily)
- NYISO transaction data (monthly or in accordance with NYISO schedules)
- LIPA and Con Edison site billing data and building hourly load data (monthly).

The Signature System consists of metering devices, DataNodes, and InfoNodes installed at select sites to collect and compile site generation and load data. The InfoNodes at each site are configured to collect data from metering devices. On a daily basis, the DMC contacts each InfoNode to retrieve all data collected. After the data are downloaded, they are validated. Any download errors are reviewed daily by the DMC operator and corrected. Following this, the data are stored in a database.

Three sources of data are currently being used by the Signature System InfoNodes. These are DataNodes, generator meters, and utility meters. Data are collected on a near real-time basis by the InfoNodes and then retrieved by the DMC daily. It is possible to view the near real-time data directly from the on-site devices over the Internet. It should be noted that for the utility meters, a device known as the ADAM Module is installed to read a utility-installed pulse initiator. It is this device that is connected to the InfoNode.

Although all of the data are retrieved automatically, there is always a manual review of the download logs and data to ensure quality control. Any errors or problems are promptly corrected. This manual review provides another layer of quality control.

The DMC also retrieves DAM price data from the NYISO. Each day by 11 a.m., the NYISO posts DAM prices for the next day. These prices are used in the engine management strategy (EMS) developed by Electrotek. This strategy can be used to buy and sell energy in the DAM. The DMC automatically retrieves the DAM prices posted at the NYISO Web site shortly after 11 a.m. each day. These prices are automatically loaded into the DMC database. With the EMS, the DAM prices will determine how much energy is bought and sold in the DAM and how resources will be dispatched.

Hourly temperature and humidity forecasts are also retrieved by the DMC. These forecasts are sent four times a day to Electrotek by a commercial service, the AWIS Weather Services Co.<sup>5</sup> The data are then placed into the DMC database. This download is the principal input of hourly load forecasts for each site participating in the EMS. These temperature and humidity forecasts as well as the hourly load forecasts are used to calculate each participant's hourly generating cost. All of these data are stored in the DMC database.

Upon completion of the data download, the DMC performs a set of operations related to portfolio management and the EMS. Two operations are performed in support of this: the calculation of hourly load forecasts for each site participating in the EMS and the determination to run generators to reduce the peak-day capacity requirement.

The load forecast is calculated for each hour at each site. To calculate a site's load forecast, the forecast model uses a set of regression equations, one for each hour. Using the most recent temperature and humidity forecast, hourly load forecasts are developed.<sup>6</sup>

The load forecast is developed not only to estimate each site's hourly load but also to calculate each site's generating cost. This running cost is determined by the hourly load forecast and the temperature and humidity forecast. The running cost is then used in the EMS to determine how to bid the resources in the NYISO markets and how to dispatch the resources if the bid price is accepted.

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<sup>5</sup> AWIS Weather Services, Auburn, Alabama, <http://www.awis.com>

<sup>6</sup> More detailed explanations of forecast algorithms and their accuracy are presented in Sections 5 and 6.

A final function of the DMC is tracking customer registration, performance, and reporting. The hourly interval load data for each participant, as well as generator output if so metered, is retrieved. During curtailments, all loads and outputs are closely monitored. In addition, consistent with all requirements, settlement and test data are submitted to the NYISO.

#### **4.1.2 Communication Control and Data Collection System Reliability**

Every morning, a DMC operator checks all communication patterns with on-site data collection instruments. Because most buildings are equipped with LAN lines, the operator must contact each building separately. During each contact, the operator checks connections and verifies the reliability of information. If a problem cannot be corrected remotely, the operator calls or e-mails the ADC for technical assistance.

Another responsibility of the data operator is to compile a monthly system report, a document that contains information about all problems and their causes, detection time, and repair time.

#### **4.1.3 Web Site Support and Maintenance**

A central place for the operation of the DG aggregation system, the DGEnterprise Web site was designed and developed to work automatically with minimum manual operations. Nonetheless, there are several operator activities. These include:

- Converting input data format for download into the Web site database
- Periodically upgrading the Web site with new features, requirements, functions, and pages
- Continuously testing and debugging DGEnterprise software to identify and correct programming errors
- Repairing failures caused by servers and other hardware components.

These problems require the constant attention of programmers and software/hardware engineers.

#### **4.1.4 Troubleshooting**

##### **4.1.4.1 Download Failures**

Downloads can fail for a multitude of reasons. For example, failures may be due to modem or network problems at the DMC. In these cases, the technical coordinator contacts the information technology staff at the DMC and reports the problem. Once the problem has been resolved, the technical coordinator initiates on-demand downloads. Downloads also fail because of problems in the field. These problems include equipment failures and connection problems. In these cases, the technical coordinator attempts to contact the InfoNode(s) that failed to determine if the problem is a connection problem. If there is a connection problem at the DG client site, the technical coordinator reports it to the field support technicians at the ADC.

#### **4.1.4.2 Data Problems**

Although data problems occur less frequently than download failures, the technical coordinator may find such a problem while reviewing data. Data problems may result in data gaps. These may be caused by a connection failure between the InfoNode and DataNode. DataNode setup errors or problems with firmware upgrades may also cause data problems. The technical coordinator gathers information, such as data plots or DataNode setup sheets, and reports the problem to ADC field support staff.

### **4.2 Aggregation Dispatch Center Management**

The management of the ADC is a critical element of the aggregation process. It is here that management of the DG resources takes place and all dispatch calls are received from the NYISO and the LSEs.

A series of activities take place here. These include:

- Registration
- Dispatch of generators
- Reporting
- Settlement
- Peak hunting
- NYISO bidding
- ADC system maintenance.

These activities comprise the daily operations of the ADC.

#### **4.2.1 Registration**

The registration process accounts for many of the administrative functions of the ADC. In the registration process, each participant is registered in the database. Because each customer may participate in any of the NYISO or LSE programs, each has its own program registration requirements—and some are more onerous than others. All sites are registered as soon as all requirements have been satisfied. Registrations for NYISO programs are done for each capability period (May–October and November–April). The registration process requires typical customer information (such as name, address, phone number, fax number, and contact person) and historical billing information.

After a participant's initial registration, the curtailment capacity registered in the NYISO ICAP Market is adjusted based on test results and performance. This adjusted curtailment capacity (UCAP) is the amount of capacity that can be bid in the ICAP Market. All UCAP values are provided to Electrotek by the NYISO on a monthly basis and are stored in the DMC, where they are used for certification and bidding.

#### **4.2.2 Dispatch of Generators**

There are three classes of dispatch calls for the DG units in Electrotek's portfolio. The first class consists of curtailment calls from the SCR, EDRP, or LSE programs. The second class is for the peak-hunting tool, which attempts to curtail load during the hour of the NYCA coincident peak. The third class is for the EMS, which aggregates a group of sites to self-generate or purchase energy in the DAM.

##### **4.2.2.1 Curtailment Calls**

A critical function of the ADC is dispatch. Generators can be dispatched from different programs, and dispatch for NYISO or LSE curtailments and Electrotek's EMS are managed differently.

Upon a curtailment notification, a series of steps is immediately initiated. For NYISO curtailment calls, notification is by e-mail and phone. In addition, the NYISO usually provides a pre-activation notice, which is typically delivered the prior day. Immediately upon receipt of a pre-activation notice or a notification, the ADC forwards an e-mail notification to designated individuals. In addition, phone or pager contact is made with select individuals to confirm notification. Notification from the LSE programs is done by phone. Upon receipt of this phone call, the ADC operator sends out an immediate e-mail notification to all designated contacts. This is followed up with phone calls to confirm notification and to get estimates of the capacity and duration of generation to be provided.

When Electrotek contacts participants by phone, the operator asks each site how much capacity it expects to curtail and for what duration. This information is reported in a readiness check conducted by the NYISO prior to dispatch. The notification message to participants provides a start date and time and a stop date and time. The NYISO has the right to call off a curtailment, and if it does so, all participants are immediately notified by e-mail and phone.

With one exception (Con Edison's Distribution Load Relief Program, which seeks immediate response), the programs have notification periods of at least 2 hours. Electrotek's ADC has demonstrated a 30-minute response time. However, more complex notification and dispatch protocols may influence response times.

It should be noted that phone calls are made to only four area managers (in Manhattan, Nassau, and Suffolk and Westchester counties), and these managers are responsible for dispatch. They use two methods to start the generators: (1) site control, in which a site engineer goes to the generator and physically starts it and (2) remote startup/shutdown from the area managers' computers.

Electrotek has developed an effective, layered notification protocol. First is the initial and universal e-mail notification. Next are the phone calls to the contact person for each location. The final levels involve alternative notification channels, including cell phones and dedicated pagers.

#### **4.2.2.2 Engine Management Strategy Procedures**

The ADC operator also conducts the EMS. Several strategies were developed and tested by Electrotek. The simpler strategy was used during the field test at Long Island. This strategy is to aggregate and register a set of sites and then purchase energy in the DAM when it is less expensive than self-generation. When the DAM price is greater than the generator running cost, the generators are dispatched. The more complicated strategy was developed later and prepared for implementation in the spring of 2004.

Independent of the particular strategy, several ADC operator steps are involved in the execution of the EMS. The first step is to determine/forecast building/generator load for each hour based on hourly temperature and humidity forecasts. The ADC operator uses this load forecast, along with the temperature and humidity forecast, to estimate each generator's hourly running cost. The hourly running cost is then used to bid for the next day's energy. This process must be conducted daily.

Another part of the EMS is daily bidding in the NYISO DAM. This process begins after the hourly generator running costs are calculated. The bidding process in the DAM begins with the daily receipt of bids for the next day by 5 a.m. Bids are for blocks of energy, each with a bid price. Using these bids, the NYISO calculates locational-based marginal prices using the Security Constrained Unit Commitment program. The locational-based marginal prices and notifications are then posted by 11 a.m. for the next day.

If a site were to be dispatched, an operating schedule would be forwarded to all EMS participants by 2 p.m. for the next day. The operating schedule is determined by evaluating the generator running costs and the capacity requirements, which the ADC operator does.

#### **4.2.2.3 Peak Hunting**

The ICAP requirement of an LSE or direct customer is set at the hour of the system coincident peak. If an LSE or direct customer can reduce its load during the hour of the coincident peak, it can reduce its ICAP requirement. The peak-hunting program is used to determine if a day is a candidate for the system coincident peak and if generators should be dispatched to potentially reduce the ICAP requirement. A detailed description of the peak-hunting tool is provided in [8].

Peak-hunting operations are conducted only during the summer months, when the NYCA coincident peak is set. Some of the tasks associated with peak hunting are coincident with activities for the EMS. Like the EMS, the peak-hunting program requires an hourly temperature and humidity forecast for every weekday. Once the forecast is available, it is used in the peak-hunting program to estimate whether the next day is likely to be the day of the system coincident peak.

#### **4.2.3 Reporting**

Most reporting and settlement activities are for the NYISO. Two reports are required for the NYISO: test results and monthly ICAP certifications. Each is detailed below.

During any capability period, the NYISO has the right to call for a test of the registered SCRs. A test is conducted just like a curtailment and has a 2-hour notification period. A test lasts for 1 hour. An SCR must demonstrate its capacity every capability period through a curtailment or a test. If no curtailment is called, a test is performed. Typically, two tests are conducted during the winter capability period. A participant only needs to demonstrate its capability for one test.

ICAP certifications are required of all registered and sold ICAP resources. Each ICAP supplier must submit an NYISO certification form by the 20th day of each month. In its monthly certification, each ICAP supplier that has been derated must certify that it has procured sufficient additional capacity to cover any shortage. All capacity that has been sold in the ICAP Market or through bilateral transactions must be certified.

#### **4.2.4 Settlement**

Electrotek's SCR and EDRP sites have separate settlement procedures. Participants in LSE programs do not have settlement reporting. For ICAP SCRs, when events or tests are called by the NYISO, all participants are required to provide interval load data for NYISO accounting and settlement. EDRP participants must provide other settlement files, including historical load data and customer baseline load (CBL) data.

The CBL is prepared for each participant and is the basis for calculating the curtailment. The hourly curtailment is the difference between the CBL and actual load. The two methods used to calculate CBL are the average day CBL and the weather-adjusted CBL. When an EDRP resource is registered, the participant must choose a CBL method.

The average day CBL calculation for EDRP settlement involves reviewing average hourly loads for the curtailment hours to find the five highest in a set of the 10 most recent eligible days. From these five days, the average loads are calculated by hour for the curtailment period. Thus, the CBL is the baseline from which load reduction is measured. To create the EDRP settlement files, one for each participant, Electrotek uses the hourly load data and custom software it has developed.

The second method of calculating a CBL is weather-adjusted. Under this method, a set of the 10 most recent eligible days is first developed. Electrotek has no customers that use the weather-adjusted CBL.

#### **4.2.5 New York Independent System Operator Installed Capacity Bidding**

The final operation conducted by the ADC is NYISO ICAP bidding. Three types of ICAP auctions are conducted by the NYISO during each capability period. The first is the strip auction, which is a 6-month contract corresponding to the capability period. One strip auction is held prior to each capability period. The second type of auction is the monthly auction. The monthly auction is typically held around the 12th day of each month. Finally, there is the spot (or deficiency) auction, which is held so those LSEs or direct customers that have a capacity shortfall can procure capacity.

In the bidding process, all transactions and all current and past UCAP values are closely tracked. Transactions do not have to be for all of a participant's capacity. For example, a 1.5-MW participant could sell 1 MW of capacity in the strip auction, 300 kW in the monthly auction, and 200 kW in the deficiency auction—all at different prices.

In addition, a change in a participant's UCAP value can effect participants. If, as an example, the 1.5-MW participant's UCAP value were derated from 1.5 MW—all of which is sold—to 1.2 MW, that participant would be responsible for procuring 300 kW for that month.

Because of the consequences of UCAP deratings, Electrotek has developed portfolio management procedures that improve the reliability of participants and include careful screening, sound technical analysis, and comprehensive training.

It should be noted that participants are able to view their facilities' technical and financial performance over the Internet using Electrotek's DMC.

#### ***4.2.6 Aggregation and Dispatch Center Maintenance***

The ADC involves a dearth of technology such as DataNodes, InfoNodes, phone lines, servers, workstations, Internet connections, meters, pulse initiators, wires, and modems. To keep this complex web of technology operating smoothly, Electrotek relies on a number of capabilities. These include sophisticated online diagnostic and programming skills, extensive instrumentation for portfolio management, and skilled software engineers and technicians.

On a daily basis, the ADC staff review all downloads from the sites. If problems are found, ADC staff review the data from the site and then going online to examine the device. In some cases, problems can be corrected online. In other cases, problems require a site visit by a technician. If a problem is found that requires a technician site visit, the technician is usually on-site within 48 hours.

Even with automated data retrieval, there is always a manual review of the download logs and data to ensure data quality. Any errors or problems found are promptly identified and corrected. This manual data review process provides another layer of quality control.

## **5 Long Island Distributed Generation Aggregation Experiment Introduction**

Practical implementation of the DG aggregation system was conducted in two steps:

1. Field-tests of the concept using several generators on Long Island
2. Development, start-up, and operation of the commercial-size DG aggregation system with generators in the New York metropolitan area (New York City and Westchester, Suffolk, and Nassau counties).

This section describes the field-testing of the DG aggregation system on Long Island conducted during the summer and fall of 2002.

To carry out this task, Electrotek developed a DG aggregation system with the ability to monitor and dispatch DG units and aggregate the units into a single transaction unit. This test was meant to confirm the technical validity of the concept that multiple DG units can be aggregated and dispatched to supply services in a competitive market environment.

To fulfill these objectives, the following steps were taken:

- The NYISO approved Electrotek as its first SR. SR is the NYISO designation of an aggregated collection of DG units normally not tracked because of their small individual capacities. An SR is given a PTID and modeled and scheduled as a single generator by the NYISO. This allows the SR to participate in the DAM.
- Ten facilities with 12 backup generators were identified within the selected territory and recruited for participation in the experiment.
- A set of operating procedures was developed. These procedures were necessary for participation in the energy market. They described coordination with the NYISO, dispatch of generators, and financial settlements.
- A control system was designed and implemented. This control system consisted of a Data Collection and Monitoring Center, an Aggregation and Dispatch Center, and a Field Operation, which included data acquisition and transmitting equipment installed on backup generators.
- A field test was planned and executed during the May–September period of 2002.

### **5.1 Buildings and Generators Portfolio**

The first step of this stage was to identify and solicit the participation of customers for the field test. Because of the severity of capacity issues in New York City and Long Island, the search was confined to these areas (NYISO zones J and K, respectively). For the field test, 10 customers were enlisted. All were located on Long Island.

Table 8 summarizes the sites.

**Table 8. Participating Sites**

<b>Site Number</b>	<b>Peak Load (kW)</b>	<b>Curtailment (kW)</b>	<b>Installed DG Capacity (kW)</b>
1	800	800	1,500
2	880	880	1,500
3	500	500	750
4	500	500	1,000
5	100	100	200
6	500	500	1,000
7	230	230	435
8	100	100	200
9	100	100	200
10	500	500	750
<b>Total</b>		<b>4,210</b>	

\*Maximum electrical demand of the building

\*\*Part of the building load that can be curtailed by starting its emergency generator(s)

\*\*\*Total installed capacity of emergency generators

As shown in the table, all of the sites are able to provide complete curtailment (i.e., the backup generators are able to carry the full site load).

After successfully recruiting participants, Electrotek registered them as an SR. NYISO rules require an SR that has sold capacity in the NYISO ICAP Market to participate in the energy or ancillary services markets. Electrotek then prepared to offer these resources in the ICAP Market and bid them in the DAM.

Electrotek worked closely with the NYISO to establish the first SR and develop the metering and communications systems. Upon NYISO approval, the equipment was purchased and installed. The costs for purchase and installation of the metering and communications systems for each site are summarized below:

• InfoNode	\$4,520
• GE kV-2 meter (per generator)	\$1,010
• Code-activated switch	\$500
• ADAM Module	\$500
• Relay	\$250
• KYZ Totalizer	\$1,200
• Digital subscriber telephone line	\$300
• Equipment installation	\$4,650
• Total average cost per site	\$12,930

Metering and communications equipment was procured and installed, and communications protocols were developed with the NYISO to satisfy all of its technical requirements. The total equipment and installation cost for the 10 sites was more than \$130,000.

However, LIPA did not accept this protocol. LIPA did not support the metering and communications systems and protocols agreed upon by the NYISO and Electrotek. This was puzzling because during this period LIPA was experiencing capacity deficiencies. It insisted that only its systems would be appropriate. LIPA's position made the successful establishment of the SR impossible.

LIPA also sought cost recovery from Electrotek for expenses to install equipment supporting its preferred metering and communications protocol and for meter reading services to support the SR. These costs were more than \$149,000, with annual recurring costs of more than \$95,000. These costs doomed the financial viability of the SR. In addition, the scheduling of the installation of this equipment would not allow the project to be implemented during the summer 2002 capability period.

## **5.2 Shadow Experiment**

Electrotek then deployed an alternative approach to test the viability of aggregated DG in NYISO market transactions. This approach was to establish a shadow experiment. Under this scheme, the 10 sites were aggregated and treated as a direct customer at the NYISO. In the case of direct customers, all capacity and energy requirements are purchased directly from the NYISO when it makes economic sense to do so. LIPA only provides distribution services.

The idea behind this approach was to purchase energy from the NYISO when the locational-based marginal price was less than the generation cost of the sites. Thus, under the shadow experiment, when DAM prices exceed the generation cost, power is provided by self-generation.

Under this approach, Electrotek first developed a portfolio of three planning models to manage and conduct the bidding process. These were:

- The load-forecasting model
- The generator cost model
- The dispatch optimization model.

Two models were actually modifications of similar tools. However, they were adjusted to conditions of the new approach to perform as a direct customer. The third model, the dispatch optimization model, was specifically developed for the new conditions.

### **5.2.1 Load Forecast Model**

To determine the loads of the 10 sites, Electrotek developed a load forecast for each. The load forecast tool is a linear regression model that uses the forecast of the hourly ambient temperature and humidity to estimate hourly loads for each site.

The regression model was developed by Electrotek to provide a reasonable hourly load forecast for each of the 10 locations. Electrotek then uses this forecast with other data to estimate generation costs. The regression equations were created using 1 year of historical hourly ambient temperature and humidity data as well as hourly load data for each location.

The regression equations were specifically targeted toward the hours when DG resources would most likely operate: between 8 a.m. and 6 p.m. It is during these periods that most load variation occurs. Hence, the regression equations were tuned to this period to more accurately capture the load variation attributable to the temperature and humidity index.

### **5.2.2 Generator Cost Model**

The generator cost model was developed to calculate the hourly cost of operating the generator(s) at each site. This cost is the variable cost of generation—i.e., fuel and O&M costs. The generator cost model calculates the generator load as a percentage of generator capacity based on the load forecast model for each location. Two adjustment factors are then applied. These adjustment factors provide an improved basis for calculating the running costs of the generators.

The first adjustment factor is the load adjustment, which accounts for generator performance changes observed at various levels of output. The performance of generators changes based on their output level. The relationship between output level and efficiency is effectively the heat-rate curve, which correlates electrical output and fuel consumption levels.

The second adjustment factor reflects the relationship between generator output and ambient temperature. The load on gas turbines is especially sensitive to ambient temperature. As ambient temperature rises, the output of the gas turbine decreases.

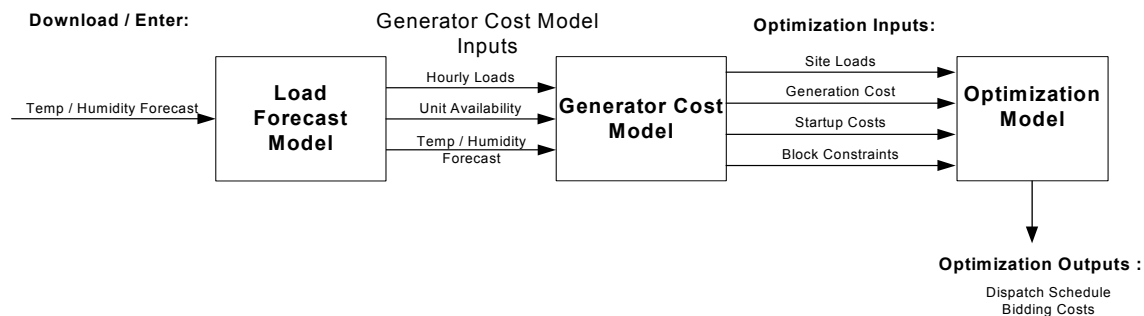
Using the hourly generator performance data described above with the O&M costs of each unit and the fuel cost, the generator cost model calculates the hourly variable cost of operating each generator. These hourly running costs are used to develop the hourly bid costs in the dispatch schedule model.

### 5.2.3 Dispatch Optimization Model

Bidding in the DAM as a direct customer is conducted for the aggregated sites in three blocks. Each block is bid separately and must be at least 1 MW. Thus, three bid prices are calculated for each hour. The specific sites associated with each block are determined with the dispatch optimization model.

Once the site loads and running costs are determined, the dispatch optimization model is used to determine how to combine the sites into three blocks to bid their capacity (or curtailment) in the NYISO DAM. Because each site's loads and running costs vary by hour, the process of determining how to combine them in the most efficient/least-cost way is a daunting task. There are 10 locations and 24 hourly costs to be combined into three bidding blocks. For each day, there are 720 potential combinations (10 sites x 24 hours x three blocks) to be evaluated.

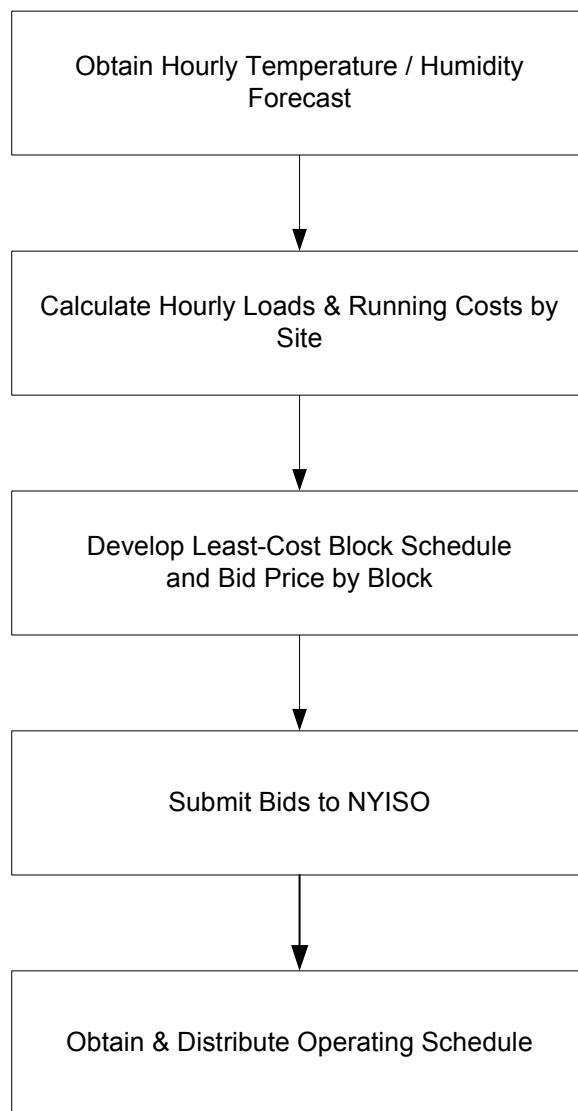
To streamline the calculation process for determining how to define the sites into the three blocks, Electrotek developed an optimization model that calculates the least-cost combination of resources. This increases the likelihood of the DAM bids being accepted. A flowchart of the model is presented in Figure 13.



**Figure 13. Dispatch optimization model**

The DAM bidding procedure consists of steps that must be undertaken in sequential order each day. These steps include developing the bid costs and preliminary operating schedules, submitting the bids to the NYISO, and, if the bids are accepted in the DAM, forwarding the dispatch schedules to the sites.

Figure 14 shows the steps to develop and submit hourly bid prices.



**Figure 14. Bidding procedure**

Under NYISO market procedures, DAM bids must be received by 5 a.m. They are then evaluated in the NYISO Security Constrained Unit Commitment program. Under this program, the NYISO dispatch schedule is developed and forwarded to all market participants by 11 a.m.

### **5.3 Shadow Experiment Results**

The results of the shadow experiment were evaluated for the period July–October 2002. Delays in the development of the SR and its final demise did not allow for the inclusion of May and June in the shadow experiment.

The goal of the shadow experiment was to evaluate the hourly cost of self-generation at each of the 10 participating sites based on forecasted hourly temperature and humidity, group these sites into three blocks to satisfy NYISO bidding requirements, and place daily bids to purchase power from NYISO based on the bid prices. When DAM prices are lower than a block's bid price, the energy for that block is purchased from the DAM. For hours when the DAM price is greater than the block bid price, energy for that block is self-generated.

Using hourly load forecasts for each of the 10 participating sites, NYISO DAM prices for Long Island, NYISO RT prices for Long Island, NYISO settlement procedures, and estimated LIPA delivery charges, Electrotek calculated the costs and revenues associated with being a direct customer bidding a price-capped load in the NYISO DAM. Details of the market mechanics and bidding process are provided in [9].

The total cost of providing the 10 aggregated sites with power under a price-capped load bid as a direct customer consists of several components. These include:

- The DAM hourly price of electricity in the NYISO market for Zone K (Long Island)
- The hourly running costs of the generators at each site based on hourly temperature, humidity, and load forecasts
- The LIPA delivery charge for the energy purchased from NYISO
- The LIPA delivery charge for the energy curtailed through self-generation
- The RT hourly price of electricity in the NYISO market for Zone K.

The RT hourly electricity price is used to reconcile the energy contracted for versus the energy bought or sold. Variances between these values are settled at the hourly RT rate by the NYISO. This reconciliation is part of the NYISO settlement process and accounts for variances between the forecasted loads and actual loads.

Table 9 shows the average bid prices by block for each month of the shadow experiment. It should be noted that the sites comprising each block changed daily based on the dispatch optimization program, which designated the sites to each block. This program was run daily to ensure block assignments were the lowest-cost combinations. As shown in Table 9, the bid prices were fairly uniform, with the lowest cost block typically bid at about \$230/MWh and the highest cost block bid at about \$250/MWh.

**Table 9. Average Hourly Bid Prices (\$/MWh)**

<b>Block</b>	<b>Jul</b>	<b>Aug</b>	<b>Sep</b>	<b>Oct</b>
Block A	230.93	252.86	252.71	246.59
Block B	246.20	228.47	234.68	231.08
Block C	248.50	247.11	263.95	244.02

Table 10 shows the minimum, maximum, and average DAM prices for Long Island for the July–September period. As shown in Table 3, the DAM prices were significantly higher for July and August than for September and October. It should be noted that the generators operated only in July and August; during September and October, all energy for the direct customer was purchased from the NYISO.

**Table 10. Long Island Day-Ahead Prices (\$/MWh)**

<b>Month</b>	<b>Min</b>	<b>Max</b>	<b>Avg</b>
Jul	21.68	498.06	64.36
Aug	21.10	599.75	67.95
Sep	21.19	198.46	50.18
Oct	19.05	148.46	47.91

Table 11 shows the hours of self-generation bid in the DAM. As shown in Table 4, August had the most curtailment hours, with each of the three blocks operated at least 16 hours. In July, there were five days when some or all of the sites provided self-generation: July 2, 3, 16, 18, and 23. In August, there were six days: August 2 and 13–16.

**Table 11. Hours of Self-Generation**

<b>Block</b>	<b>Jul</b>	<b>Aug</b>	<b>Sep</b>	<b>Oct</b>
Block A	6	16	0	0
Block B	5	19	0	0
Block C	10	18	0	0
<b>Total</b>	<b>21</b>	<b>53</b>	<b>0</b>	<b>0</b>

The amount of self-generation by month and block is presented in Table 12. As shown in the table, more than 95 MWh of electricity were provided through self-generation during the evaluation period.

**Table 12. Megawatt-Hours of Self-Generation**

<b>Block</b>	<b>Jul</b>	<b>Aug</b>	<b>Sep</b>	<b>Oct</b>
Block A	12	23	0	0
Block B	5	27.6	0	0
Block C	10	18.1	0	0
<b>Total</b>	<b>27.0</b>	<b>68.7</b>	<b>0</b>	<b>0</b>

The cost-effectiveness of being a direct customer is dependent on a number of factors. These include energy cost, capacity cost, distribution delivery charges, real-time reconciliation charges, and revenue associated with the sale of curtailments.

Customers taking distribution service in the LIPA service territory must pay an energy delivery charge. This charge applies not only to energy delivered by LIPA but also to energy supplied through self-generation. All investor-owned utilities in New York State are required to post their delivery charges under tariff. However, because LIPA is a public authority and not under the purview of the New York State Department of Public Service, it is not required to post a tariff delivery charge.

During the summer 2002 capability period, this charge would be negotiated between LIPA and the customer. Attempts to obtain a value for this charge from LIPA were unsuccessful. Thus, for purposes of the shadow experiment, three distribution service charges (low, medium, and high) were evaluated. For the summary presented here, the medium charge is used. It is \$55/MWh and is based on the distribution charges found at other New York utilities.

Table 13 presents a summary of the cost and revenue of the shadow experiment. Total energy is the sum of loads for the 10 sites by month. Energy cost is the cost of purchasing energy in the DAM, the generating cost during hours when the DA price was greater than the bid price, and the LIPA delivery charge for the total site load. The revenue numbers represent the sale of curtailments to the NYISO during periods when the DA price was greater than the bid price. For those hours, the revenue is equal to the DAM price for Long Island times the load for each block. As shown in Table 13, the average energy cost is \$105.66/MWh.

**Table 13. Shadow Experiment Summary**

	Jul	Aug	Sep	Oct	Total
Total Energy (MWh)	3,144	3,111	2,844	2,683	11,781
Total DA Energy Cost (\$)	172,130	174,343	144,506	142,600	633,580
Total DA Revenue (\$)	9,661	26,317	0	0	35,978
RT Reconciliation (\$)	979	-147	0	0	832
Total Energy Cost (\$)	161,490	148,173	144,506	142,600	596,770
Average Energy Cost (\$/MWh)	51.37	47.63	50.81	53.15	50.65
LIPA Delivery Charge (\$55/MWh)	172,902	171,087	156,407	147,572	647,968
Average Total Cost (\$/MWh)	106.36	102.62	105.81	108.15	105.66

#### 5.4 Conclusions of the Shadow Experiment

The shadow experiment demonstrated that the concept, although technically possible, was not an economically viable business model. The effect of the LIPA delivery charge is significant—roughly equal to the cost of energy. Therefore, other market opportunities were evaluated in later stages of the project, and a new strategy was developed and tested. This strategy is described in detail in the following section.

## **6 Operation of a Commercial Distributed Generation Aggregation System**

Previous sections described the development and testing of the aggregated DG system. The next step was to expand the DG system built for field-testing into a commercial operation with at least 30 MW of capacity. To accomplish the final goal of the project and demonstrate a 30-MW commercial DG system, the New York State Energy Research and Development Authority and Electrotek had to:

- Make the final selection of buildings and generators to be included in the commercial operation
- Register with the NYDEC and the NYISO buildings that did not previously participate in an NYISO energy market program
- Develop methods of procedure and training of building operating personnel for load curtailment operations
- Develop a new generator management strategy predicated on:
  - Generators participating in different energy markets and programs
  - Several generators jointly participating in regional markets similar to large central station power plants
- Modify and upgrade computer tools and programs (developed for dispatching generators, data collection and presentation, etc.) to make them more flexible for participation in different programs
- Develop a new version of the aggregation Web site DGEnterprise
- Deploy the commercial DG aggregation system
- Evaluate results for the summer and fall of 2003, including:
  - System reliability
  - System economic performance.

### **6.1 Preparation for Commercial Demonstration**

Final preparations for commercial demonstration of the 30-MW DG system were focused on:

- Integrating sites
- Evaluating the reliability of Electrotek's DG aggregation system to find potential weaknesses and develop and implement measures to prevent system failures.

### **6.1.1 Project Development**

During the period of February–August 2003, there was an increase in the number of participating DG units, and hence capacity, in Electrotek’s DG aggregation system.

This section describes the process of integrating these sites into the commercial DG aggregation system. These procedures have been described in previous sections, but there are two reasons this discussion is being provided here:

1. This capacity consists of three groups: (1) sites that participated in the 2002 shadow experiment and are ready for operation, (2) sites previously involved in separate programs in 2001 and 2002 that required review of condition and certification, and (3) new sites that must go through the evaluation and certification process.
2. Rules and requirements used by the NYISO for DG are continually revised to reflect changes in the programs. Many of these changes were based on NYISO review of summer 2001, when the first generators were registered by Electrotek for NYISO markets. Electrotek has also modified its procedures developed for additional generators into the aggregated system.

This section describes the pertinent NYISO rules and requirements, as well as specific procedures, used by Electrotek for development of the 30-MW commercial DG aggregation system.

The process of bringing resources to development crosses into many arenas. There are technical requirements such as metering and communications. There are regulatory edicts such as environmental permitting and testing. There are additional reporting and settlement requirements for NYISO markets.

There are currently three categories of participation. These are: (1) NYISO ICAP/SCR, (2) NYISO EDRP, and (3) LSE. Each of these categories has its own technical and administrative requirements, and each has its own revenue streams. These are evaluated in a project feasibility analysis. The feasibility analysis can be as detailed as data allow. For customers with a history of interval billing data, the analysis can focus on actual hourly performance.

For potential participants, the first step is to conduct a feasibility study. The feasibility study typically includes a site visit to speak with personnel and examine the generator, metering configurations, site electrical circuits and characteristics, generator and switchgear maintenance, and performance history. Next, the facility power supply—including wiring, metering, and switching—is examined. The electrical and mechanical infrastructure that has bearing on site load is also examined. All available electrical and thermal billing data for a period of at least one calendar year are obtained. In addition, generator and emergency operating procedures are reviewed and evaluated.

Once a potential project is understood, it is evaluated in a cost model to estimate its potential based on its total running cost. This evaluation, typically for a calendar year, uses a price duration curve based on NYISO DAM hourly prices at the location of the resource. This cost analysis is used to calculate the number of hours of operation and the costs and revenues of operating in those hours. These data are used to develop bidding strategies for the ICAP Market and the SCR bidding price.

The feasibility study is followed by a series of steps specific to the type of resource or category. The purpose is to establish an ICAP and a UCAP, which are explained below. Also, for each of the three categories, the technical, regulatory, and administrative procedures of the project development process are described.

#### ***6.1.1.1 New York Independent System Operator Installed Capacity***

Participation in NYISO or LSE curtailment programs revolves around the facilities' installed capacity. Installed capacity is defined by the NYISO as:

A Generator or Load facility that complies with the requirements in the Reliability Rules and is capable of supplying and/or reducing the demand for Energy in the NYCA for the purpose of ensuring that sufficient Energy and Capacity are available to meet the Reliability Rules. The Installed Capacity requirement, established by the NYSRC [New York State Reliability Council], includes a margin of reserve in accordance with the Reliability Rules.<sup>7</sup>

In the NYISO ICAP and energy markets, ICAP represents an amount of capacity a facility has to offer. Over time, this value is adjusted based on the actual capacity the facility delivered during the previous 12 months. This adjusted capacity is UCAP.

For each capability period, the NYISO calculates the UCAP requirement for each resource by multiplying the pledged capacity by one minus the average equivalent demand forced outage rate (EFORD) value of the six most recent 12-month rolling average EFORDs of all New York resources in the NYCA.<sup>8</sup>

The adjustment process consists of tracking hourly loads for each hour of curtailment or test. Curtailment providers are obligated to reduce their hourly loads to a contract minimum demand. The amount of pledged curtailment, ICAP, is defined as the difference between the average monthly peak demand of the previous year's capability period and the contract minimum demand.

$$\text{ICAP} = \text{APMD} - \text{CMD}$$

Where:

ICAP is installed capacity (pledged curtailment)

APMD is average peak monthly demand for the previous year's corresponding capability period (summer or winter).

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<sup>7</sup>NYISO Definitions Manual, Revised June 22, 1999; p. 28

<sup>8</sup> NYISO Installed Capacity Manual, Version 4, May 7, 2003; p. 11

Each hour has an EFORD ratio. This ratio is:

$$\mathbf{EFORD}_{cm,d,y,h} = \text{Min (nominated curtailment or actual curtailment)/nominated curtailment}$$

Where:

C is the customer

m is the month

d is the day

y is the year

h is the hour.

The hourly EFORDs for all test or curtailment hours in the preceding 12 months, on a rolling basis, are averaged. This average value is the EFORD of the current month. To calculate a monthly UCAP value, the ICAP value (pledged curtailment) is multiplied by the current month's EFORD.

For a facility with a registered ICAP value (pledged curtailment) of 200 kW that is called for 4 hours of curtailment, each hour's curtailment is then tracked against the nominated curtailment.

The customer's monthly EFORD value is the average EFORD of the previous 12 months of curtailments and tests. Performance is closely monitored, and monthly adjustments are based on performance by the NYISO. Assume the 200-kW customer delivers its nominated curtailment for 3 of the 4 curtailment hours called and only delivers 150 kW for the fourth hour. If, in this example, the 4 hours of curtailment were the complete set of curtailment hours for a 12-month period, the EFORD value would be 0.938, which is the average of the four hourly EFORDs: 1, 1, 1, and 0.75.

In the ICAP Market, a participant can only buy or sell his adjusted ICAP or UCAP. This may leave a seller of capacity financially exposed. For example, assume that an amount of capacity is sold in the 6-month strip auction and, over the course of the capability period, this capacity is derated based on actual performance. The seller of the capacity is deficient by the amount of the derating and must purchase that amount in the ICAP monthly or deficiency auction. And it should be noted that prices in the deficiency auction can get quite high. That is why portfolio bidding and management are critical.

#### ***6.1.1.2 New York Independent System Operator Installed Capacity/Special Case Resource Project Development Procedure***

For projects that are enrolled in the NYISO ICAP Market as SCRs, the process of going from an idea to a reality is multi-faceted. There are series of steps that are undertaken once the project is deemed economically viable. First, it must be determined that the participant will be able to satisfy the technical, regulatory and operational requirements such participation entails.

#### **6.1.1.2.1 Technical Requirements**

The technical requirements of participating in the NYISO ICAP Market are primarily related to metering and communications. All NYISO market participants must collect hourly interval data through a meter data service provider. The meter data service provider is certified by the NYP New York Public Service Commission to collect these data using PSC-approved metering instruments. Thus, a participant must first secure these services. Typically, the services are provided by the LSE for a modest monthly fee and meter and installation costs. In addition, the NYISO has a schedule for all bidding, certification, and settlement transactions.

NYISO communications requirements involve establishing the channels of communication (typically e-mail) and designating specific contacts. Under Electrotek's DG aggregation system, the NYISO contacts Electrotek, and the system then sends out notifications and schedules to all registered participants via e-mail and pager. Under SCR rules, notice can be as short as 1 hour, so communications channels must be fast and reliable.

#### **6.1.1.2.2 Regulatory Requirements**

Participation in NYISO markets is dependent on obtaining proper NYDEC certification or registration. Although new emission standards are being promulgated by the NYDEC, there are limits on NOX emissions for any resources in the NYISO markets. These limits are determined by the type and size of the generator and its hours of operation.

There are three NYDEC certifications. These are the facility registration certificate, the Title V facility permit, and the state facility permit. Working closely with each ICAP resource, Electrotek reviews existing permits and determines whether ICAP Market participation requires revisions or additional permits. When necessary, the client must secure all required NYDEC permits before it is allowed to participate in the ICAP Market.

Local regulations and ordinances (such as those regarding noise, fuel storage, or siting) may also be reviewed. Again, Electrotek reviews all pertinent issues with the participant to ensure compliance with local requirements.

#### **6.1.1.2.3 Administrative Requirements**

The administrative burden associated with ICAP Market participation covers a range of activities. The ICAP Market is divided into two 6-month capability periods. The summer capability period is May–October; the winter capability period is November–April. Each ICAP resource must be registered for each capability period.

In each capability period, if there is no call from the NYISO for SCR capacity, each SCR must submit generator test data to the NYISO to verify the capacity commitment. Electrotek provides this service. If there are any SCR calls during the capability period, Electrotek also submits all settlement data required by the NYISO.

Electrotek also handles ICAP Market bidding. As a registered NYISO market participant, Electrotek conducts all NYISO ICAP Market transactions, including offers to buy and sell capacity in the strip auction (a 6-month contract coincident with the capability period), the monthly ICAP auctions, and the monthly ICAP deficiency or spot auctions.

Starting with the summer 2003 capability period, each month, all SCRs are required to offer a curtailment bid price. The change was made to provide the NYISO with a means of stratifying the market to avoid overcommitment of SCR capacity when all of it is not needed. Electrotek also handles monthly curtailment bidding.

All ICAP capacity must also be certified with the NYISO on a monthly basis. The number of units in Electrotek's ICAP portfolio offers opportunities for sophisticated portfolio management, which Electrotek will conduct.

Finally, Electrotek handles all accounting and reporting to participants. Once all transactions are reported to and settled with the NYISO, Electrotek prepares a settlement statement for each participant and month there is a transaction. Participants can also see their own performance data via the DG aggregation system Web site.

#### ***6.1.1.3 New York Independent System Operator Emergency Demand Response Program Project Development Procedure***

For resources enrolled in the NYISO EDRP, the requirements for participation are less onerous than those for the ICAP Market. Because the EDRP is a voluntary program with no capacity requirement, the requirements are not as stringent as in the ICAP Market.

##### **6.1.1.3.1 Technical Requirements**

EDRP participants must have a New York Public Service Commission-approved interval meter read by a meter data service provider. These services are typically provided by the participant's LSE, but they can be obtained through independent entities. Certified meter data service providers can be found through the New York Public Service Commission Web site.

EDRP communications are handled primarily via the Internet, but phone, pager, and cell phone numbers must also be provided. EDRP resources are expected to respond within 2 hours of notification. The Electrotek DG aggregation system satisfies all EDRP communications requirements and handles all EDRP notifications and dispatch calls.

##### **6.1.1.3.2 Regulatory Requirements**

The regulatory requirements of EDRP are not unlike those of ICAP SCR resources. All generators must be properly registered with the NYDEC with either a Title V facility permit, a state facility permit, or a facility registration certificate. This must occur before EDRP participation is allowed.

Working with each participant, Electrotek reviews existing permits and certificates and determines whether the facility can keep that designation and, if not, the appropriate permit or certificate. If necessary, new permits or certificates must be obtained by the generator owner.

Local regulations and ordinances (such as those regarding noise, siting, or fuel storage) may also be reviewed. Electrotek reviews all pertinent issues with the participant to ensure compliance with local requirements.

#### **6.1.1.3.3 Administrative Requirements**

EDRP administrative requirements are straightforward. First is the registration process. Registration occurs once every capability period. Next, a bid price must be submitted for each resource. This bid price, if unchanged by the participant, will remain in effect for the entire capability period. It may be changed on a monthly basis.

Reporting requirements for EDRP are also straightforward. When a generator is run in support of an EDRP call, an invoice must be submitted to NYISO within 45 days of the call. Reporting can be delivered in spreadsheet or comma-separated values. The NYISO pays the EDRP clearing price to all participants called to run. The payment is for energy only.

Finally, accounting and reporting to participants is conducted. Once all transactions are reported to and settled with the NYISO, Electrotek prepares a settlement statement for each participant and month there is a transaction. Participants can also see their own performance data via the DG aggregation system Web site.

#### **6.1.1.4 Load-Serving Entity Project Development Procedure**

The development of an LSE resource is a very straightforward process. Once a feasibility study establishes the viability of participation, the participant signs up for its LSE's PSC-mandated curtailment program.

An important distinction to make when enrolling in an LSE curtailment program is whether the LSE captures the ICAP. This determines whether the participant can also enroll in the ICAP Market. The participant must decide to which program to commit its ICAP in each hour of simultaneous curtailment).

Electrotek is enrolled in three LSE programs: the Con Edison Distribution Load Relief Program, the LIPA Peak Reduction Program, and the New York Power Authority Peak Reduction Program.

##### **6.1.1.4.1 Technical Requirements**

The technical requirements of participation in an LSE curtailment program are typically handled exclusively by the LSE. If not already installed, an interval meter will be installed at the site by the utility. The meter is also typically equipped with a phone line.

Communications, primarily notifications for curtailment, are through routine channels. Refer to each utility's specific programs for specifics. Typical notification channels include phone, cell phone, pager, and e-mail.

##### **6.1.1.4.2 Regulatory Requirements**

The regulatory requirements for participation in an LSE curtailment program are the same as those for the NYISO EDRP and SCR programs. All generators must have a Title V facility permit, a state facility permit, or a facility registration certificate. These are obtained from NYDEC.

#### 6.1.1.4.3 Administrative Requirements

From a practical perspective, nearly all administrative requirements belong to the LSE. Participants are responsible only for the registration and response-to-curtailment calls. The LSE is responsible for all notifications, metering, and settlement.

#### 6.1.1.5 Project Portfolio

To date, 58 sites are enrolled in five programs. Table 14 shows the total curtailment capacity and participants of the five programs for the summer 2003 capability period.

**Table 14. Electrotek's Distributed Generation Portfolio**

	<b>NYISO SCR</b>	<b>NYISO EDRP</b>	<b>LSE LIPA</b>	<b>LSE New York Power Authority</b>	<b>LSE Con Edison</b>	<b>Total</b>
<b>Capacity (MW)</b>	30.4	7.4	4.5	3.0	9.4	<b>37.8</b>
<b>Participants</b>	32	19	18	1	4	<b>51</b>

As shown in Table 14, the NYISO ICAP Market has captured most of the capacity, with more than 30 MW and 32 customers. Fewer customers were LSE program participants, and less capacity was offered in LSE programs.

Note that a customer may enroll in both an NYISO and an LSE program. However, during a simultaneous call for curtailment, the customer can only be paid by one party. Thus, the values in the total column are not summations across rows.

The reliability of Electrotek's curtailment portfolio can be seen in the total ICAP and UCAP values. According to the NYISO UCAP report to Electrotek for September 2003, Electrotek's total registered ICAP was 30.4 MW; the total UCAP for this capacity was 28.6 MW, for an availability ratio of 94% (a 6% derating). This is very good performance.

It should be noted that the high UCAP for Electrotek's SCR capacity was not always the case. In the early stages of both the EDRP and SCR programs (summer 2002), many facilities encountered institutional inertia, mechanical failure, and procedural deficiencies that compromised the operation of the generators during curtailment calls. During this shakedown period, most of these problems were addressed. But as a result of the earlier difficulties, significant amounts of capacity were heavily derated in the summer of 2002. Table 15 shows the availability ratio, known in NYISO parlance as the EFORd for Electrotek's SCR portfolio for the summer capability periods of 2002 and 2003.

**Table 15. EFORd Values**

<b>Jun 2002</b>	<b>Oct 2002</b>	<b>Jun 2003</b>	<b>Sep 2003</b>
70.3%	53.4%	92.7%	94.1%

As shown in Table 15, there has been a substantial improvement in the performance of Electrotek's SCR portfolio over the past year. This is due to a number of factors, including better portfolio management, clearly developed and tested management and communications protocols, and a better understanding of the rules and procedures of participation. Electrotek has worked closely with all participants to ensure their understanding and has developed a customer procedures manual for this purpose. A complete listing of customer historical UCAP values is provided in the appendix.

## **6.2 Reliability Report**

### **6.2.1 Introduction**

To evaluate the reliability of the DG aggregation system, it is necessary to look at each functional element of the system, examine its failure modes, and develop a reliability index to quantify its availability. Although a certain reliability metric might be appropriate for one element, it may not be a useful measure for another element.

As a basis for assessing system reliability, four functional elements of the DG aggregation system are considered here:

- Metering systems  
Consists of utility meters, Electrotek's InfoNode, the Adam Module, and pulse initiators
- Communications systems  
Includes digital subscriber lines, telephone modems, Internet connections, and other communications-related equipment.
- Generators  
Includes the generators and all systems (e.g., fuel and mechanical) that support their operation
- DG aggregation system computer hardware/software  
Includes the computers, peripherals, and programs that comprise the aggregation system.

Two categories are used to classify failures in this report: critical and noncritical. Critical failures prevent the dispatch of generators during NYISO curtailment or dispatch calls. An example of a critical failure is a generator outage during a dispatch call. Noncritical failures do not prevent generator dispatch but compromise the operation of the system. An example of a noncritical failure is a meter or modem failure that does not prevent a response to an NYISO dispatch call but does impede the operation of a system component.

### **6.2.2 Systems**

All of the participating sites in Electrotek's DG aggregation system have at least one mode of metering, and many have multiple modes. Participation in any NYISO program or market requires an interval meter with settlement data provided each month for hourly intervals. All NYISO settlement data must be provided by a meter data service provider or meter service provider. A meter data service provider or meter service provider provides metering systems and data-reading services to customers. All meter data service providers and meter service providers must be certified by the New York Public Service Commission and use metering instruments that have been tested and approved by the New York Public Service Commission. For the most part, Electrotek has used the distribution utility serving each site as the meter service provider/meter data service provider.

Electrotek has installed two additional metering configurations at select sites. The first is a configuration that allows near real-time monitoring of site load. This is done with a utility-installed pulse initiator on the service meter that is connected to a device, the ADAM module, that records the pulses in each time interval. The second configuration involves the installation of metering equipment, the InfoNode, on the generators to provide real-time monitoring of generator output.

Fifty-eight sites are participating in the DG aggregation system, and all have utility or meter data service provider/meter service provider interval meters for site load. Forty-eight locations have utility metering systems, and 10 have meter data service provider metering systems. Twenty-five sites have a 49 generators metered with Electrotek's InfoNode. Sixteen sites have real-time metering of the service entrance site load, and 14 sites have all three metering configurations.

Thus, there is a high degree of metering redundancy. This redundancy ensures that the metering element is reliable. The only problem that could be considered critical is a failure of utility (or meter data service provider) metering. Such a failure would not allow certified billing data to be provided to the NYISO. Although there were instances of failures in components of the metering technologies, in no case was there an instance of revenue loss because of metering failure.

### **6.2.3 Communications Systems**

The DG aggregation system has several communications systems components. Hardware elements include modems, cables, pagers, cell phones, and computers; communications media include phone, digital subscriber lines, and the Internet. From an operational perspective, there are communications links between the metering systems and the utility, between the InfoNode and Electrotek, and between the utility and Electrotek.

The load data from the utility meter are retrieved through a phone line or by a meter reader. The utility load data are then validated and forwarded by e-mail to Electrotek. Generator and site load data from the InfoNode are sent via phone line, usually through a digital subscriber line connection, to the DG aggregation system. As with metering, the redundancy of communications channels provides a high degree of reliability.

#### **6.2.4 Generators**

The most critical element in the DG aggregation system is the generator. In nearly all cases, the generators were very well maintained. This is due to the criticality of their loads. Furthermore, there is a redundancy of generation at many sites.

However, if a generator, operations, control, or relay failure prevented a site from running, it would be considered a critical failure. Tracking generator reliability is done by the NYISO in its evaluation of generators in the NYISO ICAP Market. The NYISO uses UCAP to reflect adjustments to the capacity value based on actual performance. The UCAP value is a derated capacity for a site based on its performance over the preceding 12 months. For a site that has sold 1 MW of capacity (curtailment) in the ICAP Market and has only run at that value for half of the hours called, the UCAP value is 500 kW. A site that provides more capacity than the registered ICAP value during a call cannot use this surplus to offset performance deficiencies during other calls. UCAP values are provided by the NYISO to all ICAP Market participants on a monthly basis.

Fifty-eight sites are participating in the DG aggregation system, and 32 are registered in the NYISO ICAP Market. The other 26 sites are in the NYISO EDRP or the New York Power Authority and/or LIPA peak demand management program.

#### **6.2.5 Distributed Generation Aggregation System**

The DG aggregation system consists of a group of computer workstations, servers, printers, monitors, modems, and software that performs DG aggregation system operations. This system, developed by Electrotek, has a multitude of functions, including communications with InfoNodes, dispatch notification, NYISO data management (e.g., bidding, recording market prices, calculating revenues, and submitting settlement data), load forecasting, and coincident peak hunting.

#### **6.2.6 Reliability Assessment**

The overall reliability of the DG aggregation system has, in the 13-month period of July 2002–July 2003, been quite good.

##### **6.2.6.1 Metering and Communications**

The areas of metering and communications are considered jointly because, in most instances, it is not possible to separately evaluate them. Taken together in the context of critical failures, reliability has been nearly 100%. This is due first to the redundancy of metering systems. Although there have been failures in elements, none of these has been a critical failure resulting in a loss of revenue to participants. Specifically, there have been four occasions when utility metering has failed. In those instances, LIPA was unable to provide site load data. There was no consequence because these failures did not occur during months when there were curtailment calls. In addition, metering redundancy was available when occurred.

The reliability of InfoNode and ADAM (real-time site load) metering, which operate together, has also been evaluated. The overall reliability of InfoNode metering was 84%. Table 16 shows the reliability of InfoNode metering configurations.

**Table 16. InfoNode Metering Reliability**

<b>Month</b>	<b>Availability</b>
July 2002	88%
August 2002	81%
September 2002	82%
October 2002	72%
November 2002	81%
December 2002	80%
January 2003	80%
February 2003	86%
March 2003	86%
April 2003	94%
May 2003	94%
June 2003	90%
July 2003	76%
<b>Total:</b>	<b>84%</b>

Again, with the redundancy in metering, no revenue loss was incurred. It should be noted that in the first year of the NYISO demand reduction programs, the NYISO stated its willingness to provide additional time to compile settlement data if there were instances of metering failure.

#### **6.2.6.2 Generators**

Generator failures, as noted previously, can be mechanical or operational. A mechanical failure occurs when the generator is not able to run; an operational failure occurs when a generator is not dispatched when called. For the most part, the generators have proved to be reliable over the evaluation period.

Table 17 shows the reliability of ICAP SCRs during the evaluation period. The data presented are from the most recent NYISO ICAP report at the time of writing.

**Table 17. Generator Reliability**

SCR #	Locality	ICAP	Availability	UCAP	SCR #	Locality	ICAP	Availability	UCAP
315	ROS	0.3	100%	0.3	526	NYC	0.7	100%	0.7
325	NYC	0.2	100%	0.2	530	ROS	2.2	100%	2.2
501	NYC	0.8	100%	0.8	537	LI	0.5	100%	0.5
503	NYC	2.2	96%	2.1	539	LI	0.3	100%	0.3
504	NYC	5.4	93%	5	545	LI	0.9	100%	0.9
505	ROS	0.4	100%	0.4	553	LI	0.3	100%	0.3
507	LI	0.8	100%	0.8	557	LI	0.3	100%	0.3
508	NYC	0.6	100%	0.6	566	NYC	1.5	100%	1.5
509	LI	0.8	100%	0.8	567	NYC	0.4	100%	0.4
510	NYC	1.3	98%	1.2	568	NYC	0.2	100%	0.2
511	NYC	1.2	29%	0.3	569	NYC	0.726	100%	0.7
513	LI	3	100%	3	570	NYC	1.365	100%	1.3
515	LI	0.4	100%	0.4	571	NYC	1.485	100%	1.4
516	NYC	0.5	100%	0.5	572	NYC	0.284	100%	0.2
519	ROS	0.3	100%	0.3	573	NYC	0.309	100%	0.3
523	LI	0.5	100%	0.5	9117	NYC	0.228	100%	0.2

Although not all sites are included in this compilation, it accounts for roughly three-quarters of the total curtailment capacity participating in Electrotek's DG aggregation system. Table 17 shows the reliability of ICAP resources is nearly 100%.

#### **6.2.6.3 Distributed Generation Aggregation System**

The DG aggregation system could experience two types of failure: hardware and software. Since inception, there have not been any hardware failures. Regarding software failures, the system has been evolving, and upgrades have been implemented to expand capability and improve operation and interface. During system development, programming errors are found and corrected during shakedown. Such was the case with the DG aggregation system. The system has proved to be quite reliable and has not experienced any failures that have resulted in a loss of revenue for participants.

### **6.3 Results of Operation of the Commercial Distributed Generation Aggregation System**

Under this project, Electrotek started to dispatch distributed generators in 2001. These sites were not aggregated and were operated as separate generators. The experience gained was applied to the aggregation concept. The aggregation system design and development reflects this experience.

This section describes this historical experience and its influence on the design of the system. This historical experience helped Electrotek understand, evaluate, and improve the reliability of the aggregation system and its elements.

Electrotek's portfolio is participating in five curtailment programs. Each of these programs has its own measure of performance. For example, ICAP SCRs must curtail load to a contract minimum demand. Performance is measured on an hourly basis using the difference between the customer's previous year average peak monthly demand for the capability period and the customer's actual load. The hourly curtailment is the average historical peak minus the actual load. This is compared with the nominated curtailment. Remuneration is for capacity.

EDRP, on the other hand, uses a different metric. In this case, payment is made for energy. The amount of energy a participant is paid for is based on the difference between the CBL and actual load. The LSE programs have their own performance measurements.

Prior to 2003, resources were allowed to participate in both the EDRP and SCR programs. Practically all of Electrotek's portfolio did so. As such, they were eligible for both ICAP capacity payments and EDRP energy payments. For purposes of measuring performance, the NYISO developed the UCAP rating.

### **6.3.1 Summer 2001**

During the summer 2001 capability period, there were four EDRP/SCR curtailment calls:

- Aug. 7, 2001 3–7 p.m.
- Aug. 8, 2001 1–7p.m.
- Aug. 9, 2001 11 a.m.–7 p.m.
- Aug. 10, 2001 1–6 p.m.

This 4-day stretch was the first time the newly formed EDRP program was invoked, and the experience garnered was invaluable. Shortfalls were identified and corrected; operating procedures were refined.

During the summer 2001 capability period, the UCAP concept had not yet been implemented. Thus, the curtailment performance cited here is based on EDRP protocols for CBL.

Table 18 shows the EDRP/SCR portfolio performance for Aug 7. That was the first of 4 consecutive days of curtailments. Aug. 7 was a particularly hot day, with a total system peak of 30,000 MW reached for the hour ending at 5 p.m. Nine sites responded to the curtailment call. Over the course of the 4-hours, these sites curtailed 30 MWh of energy for an average curtailment capacity of 7.5 MW. Thus, for Aug. 7, 2001, the NYISO EDRP made a total energy payment of \$15,000 for the curtailment provided by Electrotek's participants.

**Table 18. Aug. 7, 2001, Curtailment (MW)**

<b>Aug. 7, 2001 PTID</b>	<b>Hour Ending</b>			
	<b>16:00</b>	<b>17:00</b>	<b>18:00</b>	<b>19:00</b>
ELE015	2.990	2.953	2.908	2.870
ELE023	0.077	0.043	0.067	0.119
ELE030	0.824	0.819	0.814	0.807
ELE031	0.833	0.827	0.814	0.805
ELE034	0.491	0.480	0.473	0.466
ELE040	0.116	0.112	0.106	0.108
ELE047	1.203	1.285	1.234	0.280
ELE005	0.779	0.775	0.780	0.785
ELE048	0.476	0.499	0.491	0.484
<b>Total</b>	<b>7.8</b>	<b>7.8</b>	<b>7.7</b>	<b>6.7</b>
<b>Total MWh</b>	<b>30.0</b>			
<b>Average MW</b>	<b>7.5</b>			

The second day of EDRP/SCR curtailment calls was Aug. 8, 2001. On this day, again characterized by high temperatures, the NYISO system peak was 30,721 MW for the hour ending at 2 p.m.

Table 19 shows the portfolio performance for Aug. 8, 2001. Fourteen sites responded to the curtailment call and provided 68.6 MWh of curtailment energy. Total revenue from EDRP was \$34,300 for August 8, 2001. The average curtailment capacity across all 4 hours was 13.7 MW.

**Table 19. Aug. 8, 2001, Curtailment (MW)**

<b>Aug. 8, 2001 PTID</b>	<b>Hour Ending</b>				
	<b>14:00</b>	<b>15:00</b>	<b>16:00</b>	<b>17:00</b>	<b>18:00</b>
ELE004	2.893	2.896	2.867	2.819	2.813
ELE005	0.824	0.866	0.810	0.801	0.312
ELE006	2.442	2.382	2.381	2.349	2.312
ELE015	3.007	3.028	3.007	2.962	2.922
ELE023	0.017	0.042	0.058	0.052	0.017
ELE028	0.344	0.345	0.343	0.338	0.335
ELE030	0.806	0.829	0.826	0.822	0.817
ELE031	0.813	0.843	0.836	0.834	0.820
ELE034	0.270	0.497	0.497	0.491	0.479
ELE038	0.002	0.000	0.000	0.005	0.000
ELE042	0.013	0.095	0.094	0.092	0.088
ELE047	1.135	0.989	1.053	1.034	0.987
ELE048	0.479	0.486	0.482	0.480	0.477
ELE049	0.683	0.717	0.714	0.702	0.695
<b>Total</b>	<b>13.7</b>	<b>14.0</b>	<b>14.0</b>	<b>13.8</b>	<b>13.1</b>
<b>Total MWh</b>	<b>68.6</b>				
<b>Average MW</b>	<b>13.7</b>				

The third consecutive day of curtailments, Aug. 9, 2001, was very hot. The system peak for that day was 30,982 MW. The curtailment was called at 11 a.m. and was in effect until 7 p.m. At 8 hours, this was the longest curtailment call.

Table 20 shows the performance of Electrotek's portfolio on Thursday, Aug. 9, 2001. As shown in the table, participation was quite good. Sixteen sites participated in the curtailment, and nearly all ran for more than the 4 hours required for SCR and EDRP. For the entire 8-hour period, Electrotek's portfolio had 125.3 MWh of curtailment energy and an average curtailment capacity of 15.7 MW. Total EDRP revenue for Aug. 9, 2001, was \$62,650.

**Table 20. Aug. 9, 2001, Curtailment (MW)**

<b>Aug. 9, 2001 PTID</b>	<b>Hour Ending</b>							
	<b>12:00</b>	<b>13:00</b>	<b>14:00</b>	<b>15:00</b>	<b>16:00</b>	<b>17:00</b>	<b>18:00</b>	<b>19:00</b>
ELE004	2.877	2.877	2.877	2.928	2.915	2.883	2.829	0.800
ELE005	0.881	0.870	0.897	0.884	0.959	0.899	0.863	0.863
ELE006	2.430	2.427	2.410	2.398	2.477	2.493	2.456	2.363
ELE007	0.278	0.323	0.359	0.397	0.405	0.540	0.590	0.438
ELE010	0.659	1.204	1.178	1.181	1.199	1.219	1.183	1.149
ELE015	3.030	3.037	3.043	3.028	3.007	2.962	2.922	2.886
ELE028	0.346	0.346	0.345	0.346	0.345	0.340	0.337	0.330
ELE030	0.826	0.827	0.829	0.829	0.826	0.822	0.817	0.811
ELE031	0.831	0.839	0.841	0.843	0.836	0.834	0.820	0.811
ELE034	0.344	0.499	0.499	0.497	0.497	0.491	0.479	0.356
ELE039	0.000	0.000	0.000	0.000	0.118	0.176	0.168	0.167
ELE040	0.114	0.113	0.112	0.113	0.114	0.111	0.105	0.108
ELE046	0.000	0.264	0.298	0.281	0.230	0.230	0.234	0.234
ELE047	1.106	1.464	1.515	0.958	1.050	1.324	1.292	0.954
ELE048	0.000	0.477	0.513	0.506	0.504	0.497	0.492	0.499
ELE049	0.676	0.680	0.681	0.689	0.710	0.708	0.713	0.624
<b>Total</b>	<b>14.4</b>	<b>16.2</b>	<b>16.4</b>	<b>15.9</b>	<b>16.2</b>	<b>16.5</b>	<b>16.3</b>	<b>13.4</b>
<b>Total MWh</b>	<b>125.3</b>							
<b>Average MW</b>	<b>15.7</b>							

The final curtailment day of the summer 2001 capability period was Aug. 10, 2001. This was the fourth consecutive day of curtailments driven by extreme temperatures. The daily peak was 29,373 MW set at the hour ending at 1 p.m. By the fourth day, "donor fatigue" was setting in.

Table 21 shows the curtailment provided by site. The response seen by Electrotek was reflective of this “donor fatigue” behavior. The number of participants was 14. The total amount of curtailment energy was 61.4 MWh for the 4-hour period. The average curtailment capacity was 12.3 MW.

**Table 21. Aug. 10, 2001, Curtailment (MW)**

<b>Aug. 10, 2001 PTID</b>	<b>Hour Ending</b>				
	<b>14:00</b>	<b>15:00</b>	<b>16:00</b>	<b>17:00</b>	<b>18:00</b>
ELE004	0.029	0.096	0.147	0.099	0.141
ELE005	0.897	0.884	0.959	0.899	0.863
ELE006	1.394	2.494	2.541	2.477	2.432
ELE007	0.159	0.373	0.389	0.428	0.394
ELE010	0.626	1.191	1.231	1.242	1.207
ELE015	2.911	3.028	3.007	2.962	2.922
ELE028	0.345	0.346	0.344	0.340	0.269
ELE030	0.816	0.829	0.826	0.822	0.817
ELE031	0.818	0.843	0.836	0.834	0.582
ELE034	0.488	0.497	0.497	0.491	0.375
ELE046	0.063	0.243	0.263	0.255	0.241
ELE047	0.584	1.224	1.097	1.085	0.810
ELE048	0.247	0.485	0.456	0.455	0.438
ELE049	0.355	0.665	0.682	0.678	0.671
<b>Total</b>	<b>9.7</b>	<b>13.2</b>	<b>13.3</b>	<b>13.1</b>	<b>12.2</b>
<b>Total MWh</b>	<b>61.4</b>				
<b>Average MW</b>	<b>12.3</b>				

The Summer 2001 curtailment calls were the first real test of the system being built. It provided Electrotek with an excellent opportunity to examine the entire process and make improvements. It also allowed Electrotek to become more creative in exploring opportunities at the NYISO for DG.

As Electrotek was developing its aggregation system, the NYISO was developing its demand-response programs. The assistance provided by these programs was exceptional. But they, too, would be adjusted to better reflect actual experience. In subsequent summer capability periods, all EDRP resources had to be registered or certified with the NYDEC. Variants on the CBL were developed, and notification protocols were improved. Summer 2001 was, for all involved, a learning experience, but one that proved the feasibility of the concept.

### 6.3.2 Winter 2001–2002

The winter 2001–2002 capability period saw a rather dramatic derating of Electrotek’s SCR capacity. Much of this was related to the lack of performance at many sites during the Summer 2001 EDRP calls. Although additional sites were enrolled, some of those already enrolled were significantly derated.

The winter 2001–2002 capability period was characterized by an unusual event: a call for SCR and EDRP curtailment. At a time when many generators were out of service on maintenance, a heat wave struck the NYCA. There were two curtailment calls. The first was April 17, 2002, 2–5 p.m.; the second was April 18 noon–6 p.m. The daily peak was 23,631 MW at the hour ending at 2 p.m.

Table 22 shows the performance of Electrotek’s EDRP portfolio on April 17, 2002. The response was not strong. Only eight sites responded to the EDRP curtailment call. They had an average curtailment capacity of 8.5 MW. Total energy was 24.2 MWh for a total revenue of \$12,000.

**Table 22. April 17, 2002, Curtailment (MW)**

April 17, 2002 PTID	Hour Ending		
	15:00	16:00	17:00
ELE005	0.5	0.0	0.0
ELE006	2.0	2.0	1.9
ELE047	1.3	1.3	1.1
ELE049	0.7	0.7	0.6
ELE007	0.5	0.6	0.6
ELE010	0.9	1.0	1.0
ELE011	0.9	1.0	1.0
ELE046	1.6	1.6	1.6
<b>Total</b>	<b>8.5</b>	<b>8.0</b>	<b>7.7</b>
<b>Total MWh</b>	<b>24.2</b>		
<b>Average MW</b>	<b>8.1</b>		

The next day, Thursday, April 18, 2002, another curtailment was called. This was again driven by extreme temperatures and many units out on maintenance. This curtailment call commenced at noon and ran until 6 p.m. The day’s peak was only 23,641 MW. However, with the shortage of available capacity, this was enough to require a curtailment call.

Table 23 shows the performance of Electrotek’s portfolio on April 18, 2002. Again, participation was light; only nine sites participated. Average curtailment was 10.4 MW, a 2.3 MW improvement over the previous day. Total curtailment energy reimbursed by EDRP was 62.2 MWh for a total of more than \$31,000.

**Table 23. April 18, 2002, Curtailment (MW)**

<b>April 18, 2002</b>	<b>Hour Ending</b>					
	<b>PTID</b>	<b>13:00</b>	<b>14:00</b>	<b>15:00</b>	<b>16:00</b>	<b>17:00 18:00</b>
	ELE005	0.0	0.5	0.6	0.6	0.6
	ELE006	0.2	0.1	2.0	2.0	2.0 1.9
	ELE004	0.1	3.4	3.5	3.4	3.4 3.4
	ELE047	0.2	1.3	1.3	1.3	1.3 1.3
	ELE049	0.0	0.6	0.7	0.7	0.7 0.7
	ELE007	0.2	0.6	0.5	0.5	0.5 0.5
	ELE010	1.0	1.0	1.0	1.0	1.0 1.0
	ELE011	1.0	1.0	1.0	1.0	1.0 1.0
	ELE046	1.6	1.6	1.6	1.6	1.6 1.5
<b>Total</b>		<b>4.2</b>	<b>10.0</b>	<b>12.1</b>	<b>12.1</b>	<b>12.0 11.9</b>
<b>Total MWh</b>		<b>62.2</b>				
<b>Average MW</b>		<b>10.4</b>				

The portfolio performance during the winter curtailments was not especially strong. This performance would be reflected in the upcoming UCAP calculation for Electrotek's resources for the summer 2002 capability period. It should be noted that for the winter 2001–2002 capability period, Electrotek's EDRP portfolio generated more than \$43,000. Winter capability periods are not usually a time when revenue streams are expected.

### **6.3.3 Summer 2002**

By the summer 2002 capability period, there were a number of changes, improvements, and enhancements to the NYISO programs and Electrotek's aggregation system. Among the changes implemented at the NYISO was UCAP. The NYISO began rating SCRs on a monthly basis and reporting these values to Electrotek and other SCRs.

As the NYISO programs evolved, so did Electrotek's DG portfolio and the DG aggregation system. By June 2002, Electrotek's portfolio reached 40 units with an UCAP value of 22.9 MW. However, some of the previously registered participants had significantly reduced UCAP value because of their poor performance in the previous curtailment calls.

In the summer 2002 capability period, two EDRP/SCR curtailments were called by the NYISO:

- July 30, 2002, 1–6 p.m.
- Aug. 14, 2002, 1–6 p.m.

Each curtailment is detailed below.

The first of the curtailments, July 30, was a Tuesday, and temperatures were more than 90°F. The system daily peak load was 29,256 MW at the hour ending at 2 p.m. Table 24 presents the EDRP performance data for the July 30, 2002, curtailment call.

As shown in the table, the response to this call was quite good. Fourteen sites responded to the call for an average curtailment capacity of 13.5 MW across the 5 hours. Total curtailment energy reimbursed under EDRP was 67.7 MWh for a total revenue of \$33,850.

**Table 24. July 30, 2002, Curtailment (MW)**

July 30, 2002 PTID	Hour Ending				
	14:00	15:00	16:00	17:00	18:00
ELE004	4.9	4.9	4.8	4.8	4.7
ELE006	1.8	1.9	1.9	1.9	1.8
ELE010	1.3	1.3	1.3	1.3	1.2
ELE012	0.5	0.5	0.5	0.5	0.4
ELE014	0.6	0.6	0.6	0.6	0.5
ELE015	1.1	1.2	1.1	1.2	1.1
ELE028	0.3	0.3	0.3	0.3	0.3
ELE030	0.8	0.8	0.8	0.8	0.6
ELE031	0.9	0.8	0.8	0.8	0.8
ELE034	0.5	0.5	0.5	0.5	0.4
ELE041	0.1	0.1	0.1	0.1	0.0
ELE042	0.1	0.1	0.1	0.1	0.0
ELE047	1.3	1.3	1.3	1.3	1.0
ELE049	0.8	0.8	0.8	0.8	0.8
ELE050	0.1	0.1	0.1	0.1	0.1
<b>Total</b>	<b>14.9</b>	<b>15.1</b>	<b>15.1</b>	<b>14.9</b>	<b>13.8</b>
<b>Total MWh</b>	<b>73.7</b>				
<b>Average MW</b>	<b>14.7</b>				

The last curtailment in the summer of 2002 was on Wednesday, Aug. 14. Like the previous curtailment, this one lasted 5 hours, from 2 p.m. to 6 p.m. Aug. 14 was a warm—though not extreme—day. The system peak was 30,432 MW, and it occurred in the hour ending at 2 p.m.

The response to this curtailment was quite good. Twenty-one sites curtailed. The average curtailment capacity was 16.7 MW. Total energy reimbursed by EDRP was 83.3 MWh for total revenue of \$41,650.

**Table 25. Aug. 14, 2002, Curtailment (MW)**

<b>Aug. 14, 2002</b>		<b>Hour Ending</b>				
<b>PTID</b>		<b>14:00</b>	<b>15:00</b>	<b>16:00</b>	<b>17:00</b>	<b>18:00</b>
ELE005	0.8	0.8	0.8	0.8	0.8	0.7
ELE006	2.0	2.0	2.0	2.0	2.0	1.9
ELE004	0.0	0.0	4.7	4.6	4.6	
ELE047	1.3	1.3	1.3	1.4	1.3	
ELE051	1.3	0.5	0.5	0.2	0.0	
ELE049	0.7	0.7	0.7	0.7	0.8	
ELE007	0.1	0.0	0.0	0.0	0.0	
ELE060	0.0	1.4	1.3	1.3	1.3	
ELE030	0.0	0.8	0.8	0.8	0.8	
ELE031	0.7	0.8	0.8	0.8	0.8	
ELE038	0.0	0.1	0.1	0.1	0.1	
ELE015	2.9	2.9	1.2	0.0	0.0	
ELE014	0.5	0.5	0.5	0.7	0.6	
ELE012	0.5	0.5	0.5	0.4	0.4	
ELE034	0.0	0.5	0.5	0.5	0.5	
ELE042	0.0	0.1	0.1	0.1	0.1	
ELE016	0.4	0.4	0.4	0.4	0.4	
ELE022	0.0	0.0	0.1	0.2	0.2	
ELE037	0.0	0.0	0.0	0.1	0.2	
ELE061	0.3	0.3	0.3	0.3	0.3	
ELE010	2.1	2.1	2.1	2.1	2.1	
<b>Total</b>		<b>13.5</b>	<b>15.7</b>	<b>19.0</b>	<b>17.8</b>	<b>17.4</b>
<b>Total MWh</b>		<b>83.3</b>				
<b>Average MW</b>		<b>16.7</b>				

The summer 2002 capability period was not difficult for the NYISO. Only two curtailments were called. For Electrotek, summer 2002 demonstrated an improved portfolio management strategy, with a more careful evaluation of curtailment resources and the amount of capacity that might be provided. Additionally, added capabilities to the ADC have continued to improve the management of an expanding portfolio.

#### **6.3.4 Summer 2003**

The summer 2003 capability period saw the introduction of the biggest changes yet. The first change was the decoupling of the EDRP and SCR programs. No longer could a participant belong to both. The second change was that offerors of SCR and EDRP capacity had to provide a minimum run price. This allowed the NYISO to dispatch based on cost and provided a means of deploying only a portion of these resources—something that was not previously done. A final change had to do with settlement calculation and reporting of SCR energy. Previously, curtailment energy was determined based on the average peak demand of a 4-month period in the previous year's same capability period and the customer's actual load. Under the new rules, energy payments use the same CBL method employed for EDRP settlement.

The summer 2003 capability period brought continued growth in Electrotek's portfolio. For the summer 2003 capability period, there were 47 participants in Electrotek's DG aggregation system. The total curtailable capacity of these participants was 29.3 MW, and this capacity was enrolled in five curtailment programs. The five programs were:

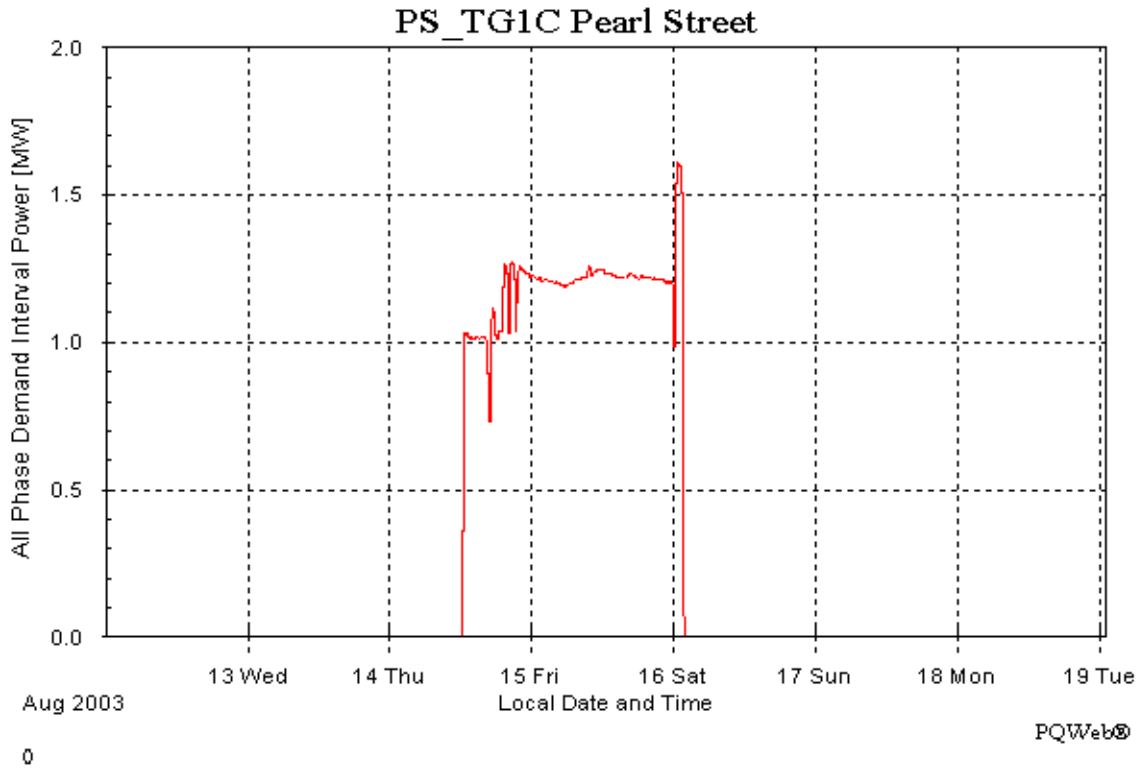
- The LIPA Peak Reduction Program (4.5 MW enrolled)
- The New York Power Authority Peak Reduction Program (3 MW enrolled)
- The Con Edison Distribution Load Reduction Program (9.4 MW enrolled)
- The NYISO ICAP (21.6 MW enrolled)
- The NYISO EDRP (7.4 MW enrolled).

Because it is possible to enroll in multiple programs, capacity totals by program are not additive.

The summer 2003 capability period had two events, and both were related to the Aug. 14, 2003 blackout. The first curtailment was for Friday, August 15, 2003, from 9 a.m. to 11 p.m. Most of New York State was in a blackout during entire time. It was also a hot, humid day. New York City temperatures reached 89°F. System controllers were concerned about an orderly restoration of power and wanted to bring load back on in smaller rather than larger increments. Curtailment could be expected to help restoration efforts. It should be noted that under SCR and EDRP rules, curtailments are for 4-hour periods.

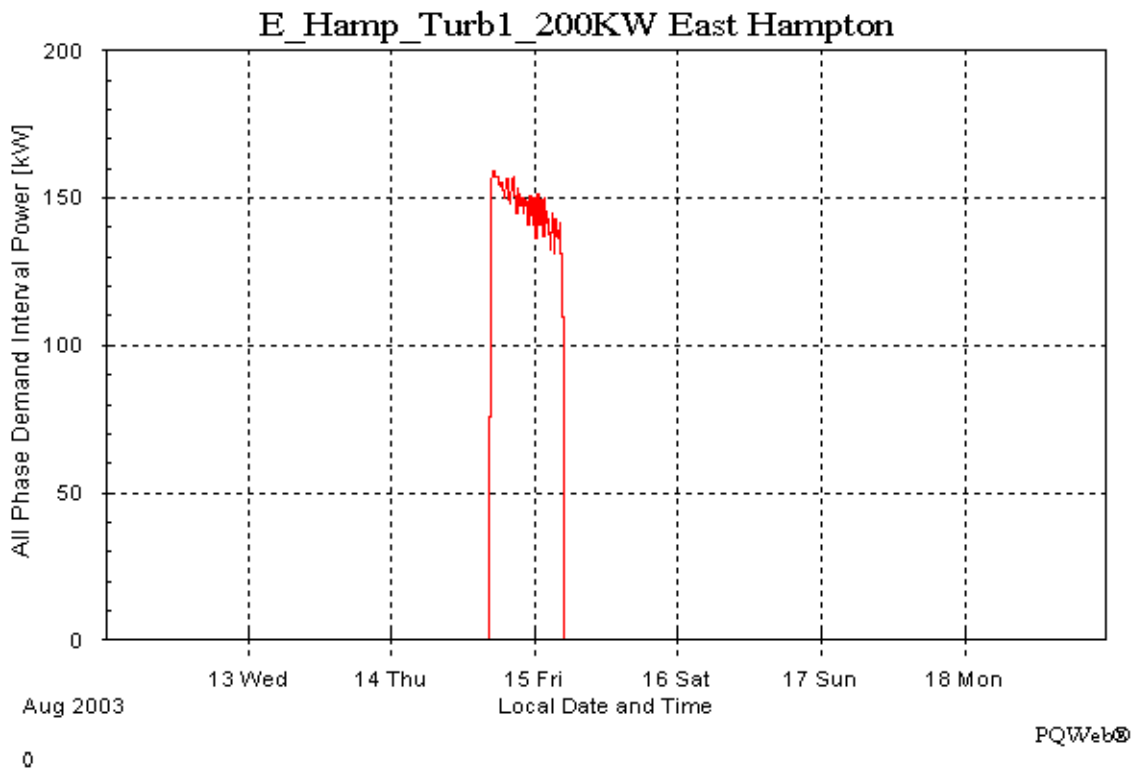
Although settlement data for these curtailments were not available at the time of writing, anecdotal evidence suggested good performance. Preliminary reports indicated that only one site did not respond to the curtailment call (because of mechanical problems).

Additional evidence suggested a good response as well. Generation data were available for sites that had generators metered under Electrotek's Signature System. Figure 15 shows the generator output for one site in New York City. This particular generator ran from around noon on Thursday, Aug. 14 to the early morning hours of Saturday, Aug. 16 and provided 1–1.5 MW of capacity during all curtailment hours.



**Figure 15. Generator output Example A**

Another site shows different performance. Figure 16 is from another location with Electrotek's Signature System. For this location, a turbine was operating from about 4 p.m. on Thursday, Aug. 14 until Friday, Aug. 15 around 4 a.m. In this instance, output was around 150 kW. However, in this case, the participant did not satisfy the curtailment call for Saturday, which began at 9 a.m.



**Figure 16. Generator output Example B**

Given the duration of this blackout, it is quite possible that facilities ran out of fuel. It might also be possible that power was restored by Friday morning.

Also of note, one of Electrotek's participants is a telecommunications company for whom reliability is paramount. Because of the timely and effective operation of its resources, none of its phones went dead, and its service remained operational.

Results of 2 days of curtailment are presented in Table 26.

**Table 26. Curtailment Results During the Aug. 15 and 16, 2003, Blackout**

	Units	August 15	August 16
Participating Sites		34	20
Peak Curtailment	MW	12.083	12.647
Total Energy Generated	MWh	242.289	82.318
Total Energy for Both Days	MWh	324.607	

#### 6.4 Engine Management Strategy

Electrotek developed a new strategy for participation in economic programs working as an LSE. This strategy is in testing and implementation and consists of a number of transactions buying and selling electricity in different power zones and running clients' distributed

generators while operating as an LSE for the client. Detailed explanations of the strategy, its components, and the tools developed for operating generators are described below.

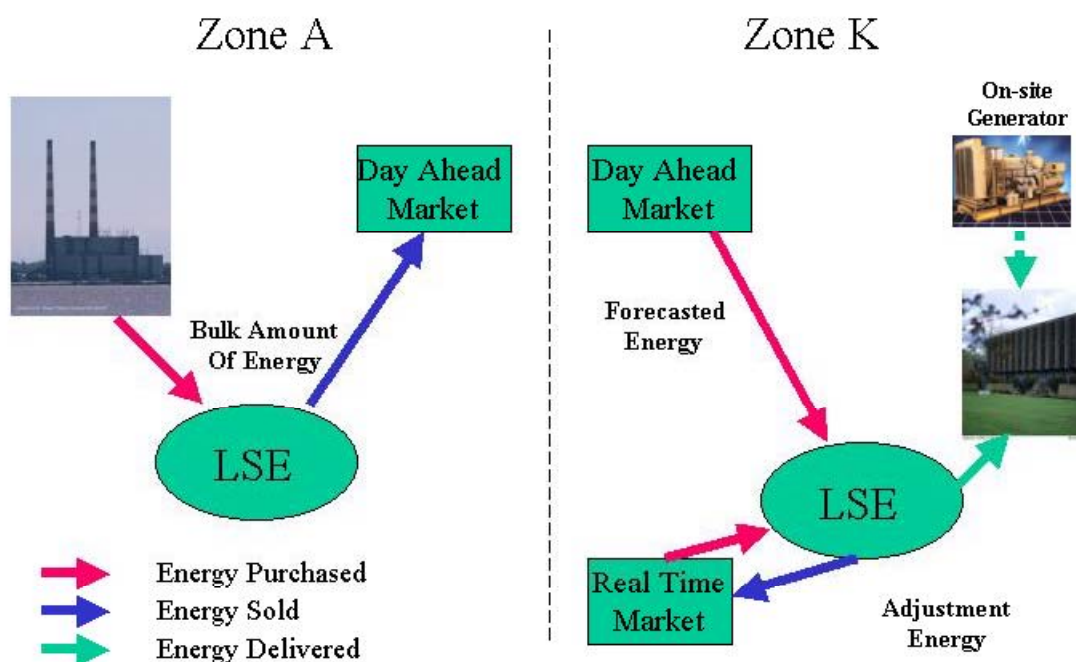
#### **6.4.1 Engine Management Strategy and Associated Transactions**

Under this initiative, Electrotek would sign an agreement with a client or group of clients on Long Island (NYISO Zone K) to serve as an LSE. Electrotek would become fully responsible for electricity supply to these customers by securing the necessary energy and capacity, plus reserve, in the market or generating electricity from client generators. This would involve the following:

- Electrotek signs an agreement with a generator to purchase baseload power for the entire year at a discounted price. The generator would likely be a power plant in the western part of New York State with access to cheap coal and, accordingly, low-cost electric energy. The amount of purchased electricity would be equal for each hour of the year. The purchased energy is sold in the DAM in Zone A in western New York.
- The amount of energy necessary to supply all clients in the strategy is purchased in the DAM in Zone K. The amount of energy necessary for each hour of the following day is determined by building electric load forecasts performed by Electrotek.
- Adjustment of the purchased amount of energy with real facility demand is performed by buying/selling electricity in the RT Market.
- If the cost of electricity (low bid cost of electricity) in the RT Market is higher than the cost of electricity generated by emergency generators, the generators are started and energy purchased in advance in the DAM is sold in the RT Market.
- Electrotek still pays transmission and other charges to LIPA.
- After all mentioned transactions are identified and calculated, Electrotek sends a final bill to the client with a markup for the LSE service.

All transactions are performed every hour. A flowchart describing these transactions is presented in Figure 17.

## Energy Flows Associated with Engine Management Strategy



**Figure 17. Transactions flowchart**

The strategy is based on a price differential between the energy purchased under contract from the power plant and the DAM in Zone K. Selling energy in the DAM in Zone A and buying it in the DAM at Zone K will provide savings on transmission charges. These transmission charges are expected to be relatively constant around the year. The low bid cost of electricity at Zone A is always lower than the low bid cost of electricity at Zone K, but these costs are correlated, so the difference between them is expected to be more or less stable.

Two most critical elements of this strategy are the sale of electricity in the DAM at Zone A, and the purchase/sale of electricity in the DAM at Zone K.

- For some hours (e.g., at night) the low bid cost of electricity at Zone A can be lower than the price paid for electricity to the power plant. Analysis conducted by Electrotek shows that, on average, this transaction will be marginally profitable for the LSE or at least should not have a negative effect on the operation in the long run.
- Energy in Zone K is purchased in accordance with the load forecast of buildings included in the strategy. The difference between purchased energy and real building demand could be purchased or sold in the RT Market. The cost of this adjustment may be prohibitive if the difference is large and if the variance between the low bid cost of electricity of the DAM and low bid cost of electricity of the RT Market is significant. The key factor in risk reduction for this strategy is the quality of the load forecast because the variance defines financial exposure.

The key factor in risk reduction for this strategy is the quality of the load forecast because the variance defines financial exposure.

This strategy was modeled and extensively tested based on data from the summer and winter of 2003. The following sections describe the model and results of its testing. Electrotek is engaged in developing contracts with clients and generators. Operation of this strategy was expected to start in late 2003.

#### **6.4.2 Accuracy of Algorithms Developed for the Engine Management Strategy**

Operation of the EMS requires accurate predictions of electric loads for separate buildings and the group of buildings. This forecast determines how much energy will be purchased in the DAM to supply the client load. In addition, the building load forecast is one of the main inputs for the cost of electricity generated by DG and, thus, is one of the main parameters of the LSE decision-making process of whether to buy electricity from the energy market or generate it. Algorithms for load prediction were developed by Electrotek in its previous report and are evaluated here for refinement.

##### **6.4.2.1 Algorithm Design**

In general, building electric load consists of the electric demand of the industrial equipment; the electric demand of the building heating, ventilation, and air conditioning system; and the demand of the rest of the mechanical and electrical equipment (such as elevators, pumps, and lighting). The electric demand of industrial equipment is dependent on the business operation schedule (the number and schedule of shifts for industrial and commercial buildings or working hours for office buildings) and the demand of the rest of the building general mechanical equipment (except the heating, ventilation, and air conditioning system). The electric demand of the building ventilation system is more or less stable throughout the year. Heating and air conditioning are highly dependent on weather conditions (i.e., ambient temperature or the temperature-humidity index) and during cold and hot periods represent a significant part of building electric load. In turn, the operation of air-conditioning equipment depends on building design characteristics (e.g., size, location, wall material, type of windows, and type and size of air-conditioning and other equipment), purpose (i.e., industrial, commercial, or office), and operating schedule (e.g., of major equipment and personnel).

Each building has a unique combination of these factors. Thus, it is not practical to build an empirical equation to reflect their influence.

In addition, some effect on algorithm accuracy may be implied by “building drift,” which is the change of building characteristics over time (such as changes in the number of building tenants, new equipment, and the aging of equipment). Several precautions were taken to make these algorithms more precise.

- Electrotek applied an approach used by the NYISO to develop the power system load forecast. This approach consists of developing separate equations for each of 24 daily hours so building-specific schedules for personnel and equipment operation and building-specific design and technical characteristics can be taken into account.

An analysis of load curves of several client buildings showed that equations for hourly forecasts are close for all business days. Load curves for weekend days are flatter, and the relationship between building load and ambient air temperature can be described with good accuracy for all 24 hours using only one equation.

- To compensate for “building drift,” it was decided that the algorithms should be updated periodically with data on building load and weather. The first set of algorithms was built using data collected during the summer months of 2002. More recently, all the algorithms were updated with information from June 2003. Electrotek is planning to update algorithms every 2 months.

#### **6.4.2.2 Algorithm Accuracy Analysis**

The DAM requires the submission of bids to buy or sell electricity by 5 a.m. the previous day. Thus, the energy to be purchased for this day is calculated using a weather forecast obtained 36–48 hours before the real event. Thus, the accuracy of the building load forecast depends on the accuracy of the algorithm itself and the accuracy of the weather forecast.

##### **6.4.2.2.1 Algorithm Accuracy**

The accuracy of the algorithms developed for the eight buildings on Long Island was evaluated by comparing real hourly building load data from June 2003 (obtained from LIPA) with building load calculated with real ambient temperature measured at the Central Islip.<sup>9</sup>

Table 27 shows the results of this evaluation.

For each of these buildings, and hence for total demand, the following information is presented:

- Average real hourly load in kilowatts
- Maximum absolute error in kilowatts
- Maximum error in percent of real load
- Average hourly error in kilowatts
- Average hourly error in percent.

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<sup>9</sup> The Central Islip weather station was selected as the central weather reference point for all buildings on Long Island. The weather station is located in Central Park. A similar central weather reference point is used for all buildings located in Manhattan

**Table 27. Building Load Forecast Accuracy (June 2003)**

	Building Load		Absolute Error		% Error	
	Average Hourly Real kW	Average Hourly Forecast kW	Average Hourly kW	Maximum Hourly kW	Average Hourly %	Maximum Hourly %
Hempstead	409	409	10	38	2.52	8.75
Bayshore	361	372	20	70	5.72	20.94
Brentwood	757	746	14	96	1.81	12.98
Deer Park	783	749	35	84	4.50	11.27
Floral Park	470	467	17	89	3.63	17.07
Garden City	2,414	2,411	49	328	2.04	12.91
Huntington	471	471	17	84	3.74	19.83
Smithtown	409	400	14	55	3.25	14.56
<b>Total</b>	<b>6,075</b>	<b>6,028</b>	<b>47</b>	<b>551</b>	<b>0.74</b>	<b>8.87</b>

The accuracy of algorithms for most buildings is 3%–6%, though it is less accurate for some buildings. It should be noted that the error has a random character without any recognizable patterns; therefore, the average error of total load for all buildings is 0.74% and the maximum absolute error is 8.87%.

#### **6.4.2.2.2 Weather Forecast Effect**

Electrotek has a contract with AWIS, a weather forecasting company. Every 6 hours, AWIS supplies Electrotek with a weather forecast for the next 240 hours (10 days). The forecast includes data on ambient temperature and humidity at the selected weather station. For the building electric load forecast, only ambient temperature is used.

Data collected over an 8-month period enabled Electrotek to perform an analysis of ambient temperature forecast accuracy changes—from the first forecast made for the selected time point 240 hours before the actual event to the last one made in the evening of the previous day. Analysis of forecast data collected for June–August 2003 showed that, typically, the forecast made 50 hours before the event differed from the real ambient air temperature by not more than 1°F –2°F.

For example, results for a randomly selected summer day (June 15) are presented in Table 28 and Figure 18. Here, forecasts made at 6 p.m. every day starting 10 days prior to June 15 are compared with actual ambient air temperatures at 7 a.m., 11 a.m., and 3 p.m. on June 15. The first line of each sample shows the hours between time of forecast and real event. The second line contains forecasted temperatures. The third line shows the differences between forecasted and actual temperatures (a negative value means that the forecast was lower than the actual temperature, and a positive value means that the forecast was higher than the real temperature).

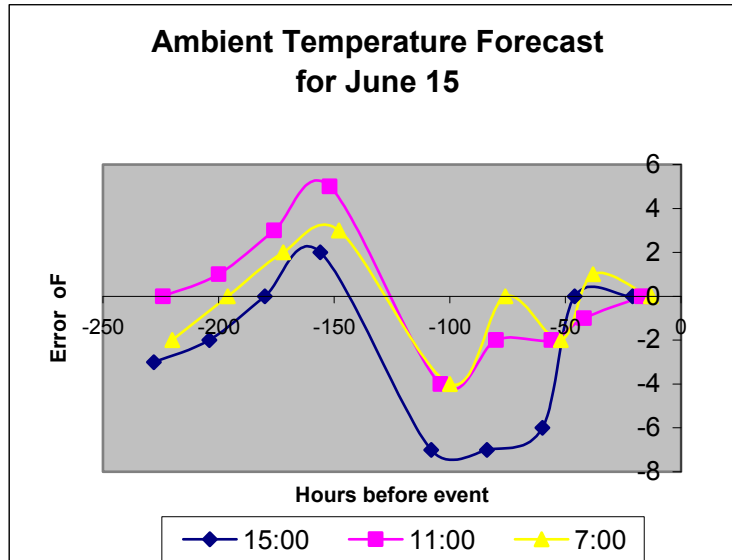
**Table 28. Accuracy of Weather Forecast**

	Date of Forecast*									Real Temp	Event Time
	6/5	6/6	6/7	6/8	6/10	6/11	6/12	6/13	6/14		
Hours before event (hr)	-228	-204	-180	-156	-108	-84	-60	-46	-21		
Forecast temperature (°F)	75	76	78	80	71	71	72	78	78	78	15:00
Difference between forecast and real temperature (°F)	-3	-2	0	2	-7	-7	-6	0	0		
Hours before event (hr)	-224	-200	-176	-152	-104	-80	-56	-42	-17		
Forecast temperature (°F)	71	72	74	76	67	69	69	70	71	71	11:00
Difference between forecast and real temperature (°F)	0	1	3	5	-4	-2	-2	-1	0		
Hours before event (hr)	-220	-196	-172	-148	-100	-76	-52	-38	-13		
Forecast Temperature (°F)	63	65	67	68	61	65	63	66	65	61	7:00
Difference between forecast and real temperature (°F)	-2	0	2	3	-4	0	-2	1	0		

\*Every day, forecast was made at 6 p.m.

Data presented in Table 28 are plotted in Figure 18. The average difference between the actual ambient temperature and its forecasted value is  $\pm 2^{\circ}\text{F}$  for all predictions made 50 hours or less before the event. The forecast made 12–20 hours before the event (at 6 p.m. of the previous day) generates a forecast that is almost equal to the actual temperature. A forecast used for bidding should be obtained for 6 p.m. the previous day; it is used to predict temperatures for the next day, which starts after midnight of the bidding day. The time between the forecast and the real event will be 30–53 hours.<sup>10</sup>

<sup>10</sup> Assuming that the purchase of energy is planned for the entire day of June 15, the bidding process must be accomplished at 5 a.m. on June 14 using the forecast made at 6 p.m. June 13 or 30 hours before 12 a.m. of June 15 and 53 hours before 11 p.m. of June 15.



**Figure 18. Accuracy of weather forecast**

Algorithms for building load predictions are based on the correlation of building load and ambient air temperature. Actual temperatures for each hour at the Central Islip were used to develop load forecast algorithms for buildings located on Long Island. Under the EMS, the temperatures forecasted 36–54 hours in advance were used. As shown above, a  $\pm 2^{\circ}\text{F}$  variance between the forecasted and the real temperature was obtained. To evaluate the effect of such a difference on the building load forecast, data on real and forecasted temperatures along with real and forecasted building load for June and July of 2003 were analyzed. The analysis showed little or no effect of this variance. Data for another day of one of the buildings included in the EMS project was taken on June 15, 2003, and are presented in Table 29.

**Table 29. Effect of Weather Forecast on Building Load Forecast**

Time	Temperature (°F)		Building Load (kW)			Error (kW)		Error (%)	
	TF	TR	LTf	LTr	LR	Etf kW	Etr kW	Etf %	Etr %
0:00	68	67	418	415	406	13	9	3.13	2.22
1:00	67	67	415	415	405	10	10	2.58	2.52
2:00	66	66	412	412	402	10	10	2.45	2.46
3:00	66	64	412	405	401	11	4	2.65	0.98
4:00	65	63	408	401	397	11	4	2.77	1.02
5:00	62	61	398	394	396	2	-2	0.44	-0.44
6:00	62	61	398	394	393	5	1	1.20	0.31
7:00	66	63	412	401	390	21	11	5.47	2.81
8:00	66	66	412	412	394	18	18	4.48	4.50
9:00	66	70	412	425	398	13	27	3.30	6.71
10:00	68	71	418	429	406	13	23	3.08	5.66
11:00	70	72	425	432	407	19	25	4.58	6.23
12:00	71	75	429	442	417	12	26	2.91	6.21
13:00	73	76	435	445	419	16	26	3.86	6.24
14:00	78	78	453	453	422	30	30	7.13	7.19
15:00	78	74	453	439	434	18	5	4.24	1.05
16:00	75	74	442	439	423	19	15	4.48	3.62
17:00	74	73	439	436	427	12	9	2.80	2.03
18:00	72	72	432	432	423	9	9	2.17	2.13
19:00	70	70	425	425	408	18	18	4.35	4.33
20:00	67	69	415	422	405	10	17	2.40	4.15
21:00	66	68	412	418	410	2	9	0.44	2.11
22:00	64	66	405	412	408	-3	4	-0.68	1.01
23:00	63	64	401	405	406	-4	-1	-1.10	-0.23
						abs max	30.10	30.38	7.13 7.19
						abs ave	11.80	12.77	2.88 3.12

Here:

Tf – Temperature forecast made at 6 p.m. on June 13 or 30 hours before June 15 starts

Tr – Real temperatures occurred on June 15 at the Central Islip weather station

LTf – Building load calculated based on temperature forecast

LTr – Building load calculated based on real temperatures

LR – Real building load at the building

EtfkW – Difference between real load and load calculated using temperature forecast (kW)

EtrkW – Difference between real load and load forecasted using real temperature (kW)

Etf % – Difference between real load and load forecasted using temperature forecast (%)

Etr % – Difference between real load and load forecasted using real temperature (%)

ABS MAX – absolute maximum error

AVE – 24-hr average error

The use of forecasted temperatures changes average 24-hours error by only 0.24%, and the change in maximum absolute error is only 0.06%. This difference is negligible.

#### **6.4.3 Model of the Engine Management Strategy**

A spreadsheet model was developed for evaluation of the EMS. The model mimics all transactions described above and can conduct sensitivity analysis to evaluate the effects of different decisions on the profitability of the operation. It consists of two workbooks. The first workbook contains information about the amount and cost of electric energy purchased and sold in Zone A and purchased and used in Zone K as well as the total energy used for the month during on-peak, off-peak, and inter-peak periods. These data are used in the second workbook to calculate the costs and fees associated with the purchase and delivery of electricity to customers.

#### **6.4.4 Shadow Experiment With the Engine Management Strategy for 2003 Data**

Electrotek is working on the contract with a client for implementation of the EMS. The contract should include operation of 8–10 buildings, for which Electrotek will serve as an LSE (i.e., be fully responsible for supplying electric energy to these buildings). Until then, Electrotek is running a shadow experiment using real monthly data starting from June 2003.

The experiment simulates all transactions included in the EMS using the following data:

- Real building electric load for eight buildings located on Long Island
- Real DAM and RT Market low bid costs of electricity
- Ambient air temperature forecasts made 30 hours before the day starts.

Results of this experiment will be presented in the next report.

## **7 Conclusions**

The DG aggregation system has evolved into a full-scale commercial operation with more than 50 DG sites in five curtailment programs. The technical and economic viability of the concept has clearly been demonstrated. It has been reinforced by the continued growth in enrollment and diversity of programs.

Three years of development, building, and operation of the DG aggregation system lead to the following conclusions.

### **7.1 Distributed Generation System Design and Cost**

The architecture of the system has proved efficient and reliable. Use of the Web site not only as a central information source but also as an operating platform for the entire DG aggregation system is a promising option—even it still needs more development.

With the NYISO recognizing only metering equipment installed and maintained by meter service providers and meter data service providers, installation of metering equipment by the aggregator is not required except when the aggregator seeks additional data. In many facilities, an additional output (KYZ-type) from the utility meters might successfully serve these information needs. This simplifies requirements and reduces the cost of aggregating DG into the system.

### **7.2 Distributed Generation System Flexibility and Reliability**

The DG aggregation system is flexible in several ways:

- It can be expanded easily with new sites. In a 4-month period, the enrollment expanded from 10 to more than 50 sites.
- The system can adopt and operate sites with different configurations of metering, monitoring, and control equipment.
- The system can be adapted to new curtailment programs. Currently, it is operating in a manner consistent with the requirements of five LSE and NYISO programs.

The reliability of the DG resources in the early stages was not very good. Through an aggressive quality control effort, recruiting became more selective, enrollment became more targeted, portfolio management was improved, and generator performance was improved. For September 2003, the availability rate of Electrotek's SCR participants is more than 94%.

### **7.3 Distributed Generation System Economic Efficiency**

Operation of the DG system has shown high economic efficiency. Operating only in curtailment mode, the DG system operation made a profit in 2003 of about \$1.5 million.

Electrotek also has investigated several EMSs to use aggregated generators performing as SRs or LSEs.

First, the operation of the DG system as an SR was tested in the shadow experiment. The experiment demonstrated that the concept, although technically possible, was not an economically viable business model. This is because of the LIPA delivery charge, which is roughly equal to the cost of energy.

Next, a model of operation in which Electrotek would perform as an LSE was developed. The investigation and analysis of the EMS has shown some potential. There is clearly economic potential, and Electrotek is aggressively pursuing this endeavor to bring it into operation. The review of technical requirements is under way to ensure that all the pieces can be in place for the daily, monthly, and annual/capability period operations and requirements.

In support of EMS development, negotiations with LIPA are under way to clarify the rights, roles, responsibilities, and terms of a potential LSE arrangement. There are a multitude of technical and contractual issues to be addressed. In addition, Electrotek is compiling a list of potential generators. As the EMS progresses, Electrotek will report developments.

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## **Appendix: Unforced Capacity Data**

EDRP ID	Zone	SCR ID	Jun-01	Sep-01	Dec-01	Mar-02	Jun-02	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03
	H	315						0.2	0.1	0.2	0.3	0.3
	J	325						0.2	0.2	0.2	0.2	0.2
ELE005	J	501	0.8	0.7	0.7	0.0	0.0	0.8	0.5	0.5	0.8	0.8
ELE006	J	503	2.0	1.7	1.7	3.2	3.2	2.6	1.1	2.2	2.1	2.1
ELE004	J	504	3.3	2.2	2.2	3.1	3.1	3.2	2.9	4.3	5.1	5.1
ELE008	H	505		0.0	0.0	0.3	0.3	0.3	0.3	4.3	0.4	0.4
ELE036	K	506	0.2	0.0	0.0	0.3	0.3	0.0	0.0	4.3	0.4	0.4
ELE030	K	507	0.8	0.6	0.6	0.5	0.5	0.5	0.5	4.3	0.8	0.8
ELE048	J	508	0.6	0.1	0.1	0.0	0.0	0.3	0.3	0.3	0.6	0.6
ELE031	K	509	0.7	0.5	0.5	0.5	0.5	0.5	0.5	0.3	0.8	0.8
ELE047	J	510	2.8	0.7	0.7	1.0	1.0	1.4	0.9	0.9	1.2	1.2
ELE038	K	512	0.1	0.0	0.0	1.5	1.5	0.0	0.0	0.1	0.1	0.1
ELE015	K	513	3.2	2.5	2.5	2.9	2.9	0.6	1.4	0.1	3.0	3.0
ELE014	K	514	1.3	0.0	0.0	1.0	1.0	0.0	0.1	0.1	3.0	3.0
ELE012	K	515	0.5	0.0	0.0	0.4	0.4	0.0	0.2	0.2	0.4	0.4
ELE045	J	516	0.4	0.0	0.0	0.4	0.4	0.4	0.4	0.2	0.5	0.5
ELE023	K	517	0.3	0.0	0.0	0.3	0.3	0.0	0.0	0.0	0.5	0.5
ELE009	H	519		0.0	0.0	0.2	0.2	0.2	0.2	0.0	0.3	0.3
	K	521	0.2	0.0	0.0	0.1	0.1	0.1	0.2	0.0	0.3	0.3
ELE039	K	522	0.2	0.0	0.0	0.1	0.1	0.0	0.0	0.0	0.3	0.3
ELE033	K	523		0.0	0.0	0.5	0.5	0.0	0.2	0.2	0.5	0.5
ELE046	J	525	1.3	0.1	0.1	0.1	0.1	0.1	0.0	0.2	0.5	0.5
ELE049	J	526	0.8	0.2	0.2	0.5	0.5	0.3	0.3	0.2	0.4	0.4
ELE007	J	527	0.6	0.1	0.1	0.2	0.2	0.3	0.1	0.2	0.4	0.4
ELE001	K	529	0.2	0.0	0.0	0.2	0.2	0.0	0.0	0.0	0.4	0.4
ELE010	H	530	2.5	0.4	0.4	0.4	0.4	0.8	1.6	0.0	2.2	2.2
	K	531	0.2	0.0	0.0	0.2	0.2	0.2	1.6	0.0	2.2	2.2
ELE011	H	532	0.3	0.0	0.0	0.3	0.3	0.0	0.0	0.0	2.2	2.2
ELE029	K	533		0.0	0.0	0.3	0.3	0.0	0.0	0.0	2.2	2.2
ELE024	K	536		0.1	0.1	0.3	0.3	0.0	0.0	0.0	2.2	2.2
ELE034	K	537		0.5	0.5	0.3	0.3	0.4	0.3	0.3	0.5	0.5
ELE042	K	538		0.1	0.1	0.3	0.3	0.0	0.0	0.0	0.5	0.5
ELE018	K	539		0.5	0.5	0.6	0.6	0.5	0.1	0.1	0.3	0.3
ELE019	K	539		0.5	0.5	0.6	0.6	0.5	0.1	0.1	0.3	0.3
ELE016	K	540		0.3	0.3	0.6	0.6	0.0	0.1	0.1	0.3	0.3

EDRP ID	Zone	SCR ID	Jun-01	Sep-01	Dec-01	Mar-02	Jun-02	Sep-02	Dec-02	Mar-03	Jun-03	Sep-03
ELE013	K	541		0.2	0.2	0.6	0.6	0.0	0.0	0.0	0.3	0.3
ELE035	K	542		0.4	0.4	0.6	0.6	0.0	0.0	0.0	0.3	0.3
ELE017	K	543		0.2	0.2	0.4	0.4	0.4	0.0	0.0	0.3	0.3
ELE020	K	544		0.1	0.1	0.4	0.4	0.0	0.0	0.0	0.3	0.3
ELE021	K	545		0.5	0.5	0.4	0.4	0.0	0.0	0.2	0.9	0.9
ELE022	K	546		0.1	0.1	0.4	0.4	0.0	0.0	0.0	0.9	0.9
ELE025	K	549		0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.9	0.9
ELE026	K	551		0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.9	0.9
ELE002	K	552		0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.9	0.9
ELE037	K	553		0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.3	0.3
ELE027	K	554		0.2	0.2	0.0	0.0	0.0	0.1	0.1	0.3	0.3
ELE044	K	555		0.3	0.3	0.1	0.1	0.1	0.1	0.1	0.3	0.3
ELE041	K	556		0.2	0.2	0.1	0.1	0.0	0.0	0.0	0.3	0.3
ELE028	K	557		0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
ELE040	K	558		0.1	0.1	0.2	0.2	0.0	0.0	0.0	0.3	0.3
ELE003	K	560		0.4	0.4	0.5	0.5	0.5	0.0	0.0	0.3	0.3
ELE050	J	562		0.4	0.5	0.8	0.8	0.8	0.0	0.0	0.3	0.3
	K	563		0.4	0.5	0.4	0.4	0.4	0.4	0.4	0.3	0.3
	K	564		0.4	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3
	K	565		0.4	0.5	0.6	0.6	0.6	0.3	0.3	0.3	0.3
	J	566		0.4	0.5			1.0	1.0	0.3	1.5	1.5
ELE032	K	567		0.4	0.5			1.0			0.4	0.4
ELE043	K	568		0.4	0.5			1.0			0.2	0.2
	J	569									0.7	0.7
	J	570									1.3	1.3
	J	571									1.4	1.4
	J	572									0.2	0.2
	J	573									0.3	0.3
Total			23.3	18.3	19.0	27.6	27.6	21.0	16.7	25.9	51.2	51.2

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